COMMERCE DEPARTMENT

November 20, 2025 **PUBLIC DOCUMENT**

Sasha Bergman
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, Minnesota 55101-2147

RE: **PUBLIC Response Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G008/M-25-72

Dear Ms. Bergman:

Attached are the **PUBLIC** Response to Reply Comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Request for Change in Demand Units (Petition).

The Petition was filed on April 1, 2025, by CenterPoint Energy Minnesota Gas.

The Department recommends approval and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Dr. Sydnie Lieb
Assistant Commissioner of Energy Regulatory Analysis

JK/LB/ar
Attachment

Before the Minnesota Public Utilities Commission

PUBLIC Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G008/M-25-72

I. INTRODUCTION

Pursuant to Minnesota Rules 7825.2910, subpart 2,[1] CenterPoint Energy Minnesota Gas (CenterPoint, CPE, or the Company) filed a petition requesting a change in demand[2] units (Petition) on April 1, 2024.

On September 16, 2025, the Minnesota Department of Commerce, Division of Energy Resources (Department) filed comments. The Department recommended approval of:

- The Company's 2025-2026 Design Day calculation.[3]
- The Company's 2025-2026 Proposed Reserve margin.
- CenterPoint's compliance with annual reporting requirements resulting from the G008/M-21-102 and G008/M-21-138 dockets.

Regarding CenterPoint's proposed changes to its 2025-2026 Demand Entitlement and routine demand charges in particular, the Department's comments recommended the Commission approve CPE's proposal to add firm capacity on Northern Natural Gas (NNG) at NNG's Carlton South receipt point.

The Department also requested CenterPoint provide additional information in its reply comments regarding the following routine demand charges pertaining primarily to firm pipeline capacity (FPC) or rates:

- NNG – TFX Northern Lights 2025
- ANR Storage and Transportation Agreement
- Tenaska/CenterPoint Asset Management Agreement (AMA)
- Trailblazer rate increase
- Viking Firm Capacity Renewal.

Regarding non-routine demand changes or rates, the Department recommended the Commission approve:

- Tenaska Storage/East Cheyenne Storage LLC Agreement – (second agreement).
- BP Canada's new marketer storage agreement.
- NNG Firm Daily Delivery (FDD) Correction.

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[1] "Filing upon a change in demand. Gas utilities shall file for a change in demand to increase or decrease demand, to redistribute demand percentages among classes, or to exchange one form of demand for another."
[2] Also called entitlement, capacity, or transportation on the pipeline.
[3] The Department also recommended the Commission not require CPE to adjust its 2025-2026 Design Day calculation for the effects of electrification or decarbonization.

The Department did not provide a recommendation regarding the proposed storage and transportation agreements with ANR Pipeline in its comments. In addition, the Department identified the potential for rate impacts of NNG's 2025 Section 4 Rate Case filed with the Federal Energy Regulatory Commission.

Since the Department filed its comments, it has received additional information regarding the financial and operational benefit of physical storage as well as CenterPoint's 2025-2026 Gas Purchase Plan (GPP).[4,5] The Department is including selected information from those two sources in this response to reply comments as it appears that this information provides useful context for CenterPoint's requests in this Demand Entitlement filing.

II. PROCEDURAL BACKGROUND

April 1, 2025	CPE submitted its petition requesting a change in its 2025-2026 Contract Demand Entitlement.[6]
April 11, 2025	CPE submitted a supplemental filing correcting a calculation in the demand charges for the proposed contracts with ANR.[7]
May 29, 2025	CPE submitted its 2025-2026 Design Day.[8]
September 16, 2025	The Department filed its comments.[9]
September 26, 2025	CenterPoint filed its reply comments. [10]
October 31, 2025	CenterPoint made a supplemental filing. [11, 12]

[4] See Attachment DOC-1-RC. This attachment contains a copy of a report produced by the American Gas Association (AGA) titled "Assessing the Value of Natural Gas Storage". The report was issued April 29, 2025.

[5] See **TRADE SECRET** Attachment DOC-2-RC TS. This attachment includes a copy of CenterPoint's **TRADE SECRET** 2025-2026 Gas Procurement Plan (GPP).

[6] Request for a Change in Demand Units, Petition, April 1, 2025, Docket No. G008/M-25-72 (eDockets) 20254-217131-01 (hereinafter Petition).

[7] Request for a Change in Demand Units, Supplemental Filing, April 11, 2025, Docket No. G008/M-25-72 (eDockets) 20254-217534-01 (hereinafter Amended Petition).

[8] Request for a Change in Demand Units, Compliance Filing, May 29, 2025, Docket No. G008/M-25-72 (eDockets) 20255-219344-02 (hereinafter 2025-2026 Design Day Calculation)..

[9] Request for a Change in Demand Units, Comments, September 16, 2025, Docket No. G008/M-25-72 (eDockets) 20259-223096-01 (hereinafter Department Comments).

[10] Request for a Change in Demand Units, Reply Comments, September 26, 2025, Docket No. G008/M-25-72 (eDockets) 20259-223096-02 (hereinafter Reply Comments).

[11] Request of a Change in Demand Units, Demand Entitlement 2025-2026 Supplement, October 31, 2025, Docket No. G008/M-25-72 (eDockets) 202510-224487-02 (hereinafter: Supplemental Filng).

[12] The Supplemental Filing 1) updated the Supplier Demand/Seasonal Wing demand expense; 2) noted the Company had renewed its Viking max rate contracts that expired October 31, 2025; 3) noted the Northern Natural Gas' (NNG) 2025 General Rate Case at the Federal Energy Regulatory Commission (FERC) was ongoing and that interim rates will become effective on January 1, 2026. The Company also provided an updated customer impact analysis for additional demand-related costs the Company is requesting approval for effective November 1, 2025. This supplemental filing includes the Company's final request for recovery of its demand costs for the 2025-2026 heating season.

III. ANALYSIS

The Department begins its analysis by reviewing and commenting on the updated information included in the Company's October 31, 2025, supplemental filing. In a subsequent section the Department will discuss the rate, and bill impacts CPE's proposed increases in its Annual Demand Cost since April 1 and provide context as to how the proposed overall increase compares to prior years.

A. CENTERPOINT RESPONSES TO DEPARTMENT REQUESTS FOR ADDITIONAL INFORMATION

A.1 Northern Lights 2025

The Department's September 16, 2025, comments requested CenterPoint provide additional information on the difference between the amounts for CPE's Northern Lights 2025 Contribution-in-Aid-of-Construction (CIAC) that was approved by the Commission in CenterPoint's 2023 rate case (Docket no. G008/GR-23-173) ($13.3 million) and the CIAC the Company noted in its response to IR 8 in this docket **[TRADE SECRET DATA HAS BEEN EXCISED]**. [13]

The Company attributed the difference to its ongoing efforts to lower the cost of the 2025 capacity expansion after having estimated the CIAC to be $13.3 million in the 2023 rate case. CenterPoint stated:

> The significant amount of time and effort devoted to this process by CenterPoint Energy was to ensure that Company was making the most prudent and favorable decision for its customers with the information presented and available at the time of election. CenterPoint Energy elected to submit an offer of and was awarded Case 4 volumes of 15,000 Dth/day of additional NNG capacity. . . . This additional capacity allows for an adequate amount of reserve margin for Winter seasons 2025-2026 and 2026-2027 and gives the company time to evaluate alternate capacity options which could be less costly for customers before elections for 2027 Northern Lights Open Season commence.

The Department recognizes that CPE is continually refining its cost estimates for serving it customers and that some variation between a forecasted and actual expenditure is to be expected. This difference is a concern for the Department, but it is somewhat mitigated by the fact that the Commission approved capital true ups for CPE for 2024 and 2025 in CPE's 2023 Rate Case.[14]

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[13] **TRADE SECRET** Reply Comments at 2.
[14] *In the Matter of the Petition by CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota,* PUC Order, June 27, 2025, Docket No. G008/GR-23-173 at 5 and Order Point 1 (eDockets) 202256-220411-01 (hereinafter "2023 CPE Rate Case Order").

The Department asked CenterPoint staff as to the timing of the payment of the CIAC to NNG. CenterPoint explained that it paid the CIAC on March 31, 2025.[15] The Department will review CenterPoint's 2025 capital true-up filing when it is submitted on May 1, 2026, to determine if it is possible to pursue this issue further.

The Department recommends the Commission approve the Company's additional firm capacity with NNG – TFX Northern Lights 2025.
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A.2 Tenaska/CenterPoint Asset Management Agreement (AMA)

The Department asked for some additional information regarding two defined terms included in the AMA. In its reply comments, CenterPoint didn't provide any information regarding those two specific defined terms. The Company did provide the following information regarding the Tenaska/CPE AMA:

> As mentioned in the Company's response to Department Information Request number 17, the Company pursued entering into the AMA knowing it would at minimum receive a Company Guaranteed Optimization Value of ~$2.6 million, which is equal to what was received in Summer 2024 through capacity release revenues. . . . Being the significant increase in total dollars the Company realized in Summer 2024 from Summers 2022 and 2023 through capacity releases, the Company felt it was a prudent decision to enter into the AMA structured where the Company at minimum received revenues which matched those of Summer 2024 and potential for additional costs savings with the 60/40 revenue sharing component. It is important to consider Viking capacity is an annual entitlement the Company cannot necessarily utilize during the summer months or on warmer Winter days. Therefore, any credits realized through an AMA on Viking are Company efforts/initiatives to reduce costs for customers.

The Department asked CenterPoint to provide the "Net Optimization Value" invoices for this AMA in IR 31.[16] The Company noted in its response that for the April through September period CenterPoint's share of the revenue generated by the AMA was **[TRADE SECRET DATA HAS BEEN EXCISED]**. While the amount CPE provided didn't include the October amount of the net optimization value for the AMA, the Company's response suggests that the value of summer season capacity on Viking was like 2024. That year was the one used for the AMA's Guaranteed Optimization Value in the current agreement. Given this information, the Department concludes that the AMA didn't provide direct benefits to Tenaska that were significantly higher than those Tenaska estimated in the AMA. The Department recommends the Commission approve the Tenaska/CenterPoint AMA based on the information provided in IR 31.

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[15] See Attachment DOC-3-RC. Email dated October 7, 2025, from Donald Wynia, CenterPoint Energy to John Kundert, MN Department of Commerce.
[16] See **TRADE SECRET** Attachment DOC-4-RC.

A.3 Trailblazer Backhaul Agreement

The Department requested CPE provide the reasons why the Company decided it needed to renew the Trailblazer Agreement given that it resulted in a 30 percent rate increase. CenterPoint's response focused on the critical aspect of the Company's storage/transportation agreements with Tenaska Storage LLC and East Cheyenne Storage. Given the relatively small amount of the increase in question, the Department accepts CPE's response and recommends the Commission approve the proposal.

A.4 Viking Firm Capacity Renewal

The Department requested that CenterPoint confirm the Department's understanding that the Viking Firm Capacity Renewal agreement was merely procedural in nature as CPE is already paying the rates included in the renewed agreement under the current agreement. This request wasn't necessary in that CenterPoint provided this information in its response to information request (IR) 10.[17]

In its response, CPE responded that it had completed contract negotiations with Viking regarding the Capacity Renewal agreement and provided a signed copy of the agreement in an attachment to the IR response. The Company also provided an analysis that identified the incremental cost associated with the renewal agreement in the IR response as well.

CenterPoint also reiterated this point in its supplemental filing.

Hence the Department recommends the Commission approve the proposal.

A.5 ANR Transportation and Storage Agreement

The Department reviewed the Company's proposed costs associated with the new storage and transportation agreements with ANR. The annual cost for the contract with ANR storage is **[TRADE SECRET DATA HAS BEEN EXCISED]** effective April 1, 2025. The proposed increase is consistent with the contract which CenterPoint included in its filing.[18] The Company is also requesting recovery of the costs associated with four different transportation agreements. The total annual demand-related costs of those four agreements are **[TRADE SECRET DATA HAS BEEN EXCISED]**. Hence, the total annual cost of the ANR agreements (storage and transportation) is **[TRADE SECRET DATA HAS BEEN EXCISED]**.

CPE is also proposing the ANR storage contract's annual cost be allocated **[TRADE SECRET DATA HAS BEEN EXCISED]** between the annual demand unit Cost and the commodity unit cost as defined in the Purchase Gas Adjustment (PGA) rules. This proposed allocation **[TRADE SECRET DATA HAS BEEN EXCISED]** other storage contracts.[19] Hence, CPE is requesting recovery of **[TRADE SECRET DATA HAS BEEN EXCISED]** via the annual demand cost in the Petition.[20]

As to the particulars of the Agreement, the Company participated in an Open Season in September 2023 initiated by ANR for firm storage and accompany firm transportation services. Relative to the firm

[17] See Department Comments, **TRADE SECRET** DOC Attachment 7.
[18] Petition, **TRADE SECRET** Exhibit C1.
[19] Petition, Exhibit A.
[20] Supplemental filing, **TRADE SECRET** Exhibit A, p. 2.

storage capacity component of the transaction, CenterPoint was awarded 4.5 billion cubic feet (Bcf) of firm storage for 15 years, beginning April 1, 2025.[21]

Hence, this firm storage contract was the primary driver for the Company's April 1 filing. As noted above, the annual cost of this additional firm storage capacity is **[TRADE SECRET DATA HAS BEEN EXCISED]**.[22]

Turning to the transportation aspect of the agreement, ANR contracted with Northern Border Pipeline (NBPL) for summer season firm transportation capacity beginning on April 1, 2025. The driver for this addition was the need for CPE to move gas purchased by the Company into ANR's firm storage facility located in Michigan. The cost of this additional firm transportation capacity is **[TRADE SECRET DATA HAS BEEN EXCISED]** and the amount of summer season capacity was **[TRADE SECRET DATA HAS BEEN EXCISED]**.[23]

The three additional transportation agreements with ANR became effective on November 1, 2025. Two of those agreements covered the capacity and deliverability of the maximum daily ANR storage available. The third was an additional transport agreement. The driver for these agreements was the need to deliver gas from ANR's storage facility in Michigan to NNG's at receipt point at Ventura, where CenterPoint holds firm pipeline capacity. The annual cost of the two additional firm transportation agreements for daily capacity and deliverability is **[TRADE SECRET DATA HAS BEEN EXCISED].** The maximum daily amounts capacity and deliverability are **[TRADE SECRET DATA HAS BEEN EXCISED]**. The annual cost of the third agreement is **[TRADE SECRET DATA HAS BEEN EXCISED]** and the amount of year-round capacity is **[TRADE SECRET DATA HAS BEEN EXCISED]**.[24]

The total ANR demand-related annual cost related to the firm pipeline capacity agreements is equal to **[TRADE SECRET DATA HAS BEEN EXCISED]**. [25] The total annual ANR storage costs recovered through the demand cost is **[TRADE SECRET DATA HAS BEEN EXCISED].[26]** The total annual ANR storage/transportation costs recovered through the annual demand cost from CPE's ratepayers is **[TRADE SECRET DATA HAS BEEN EXCISED].**[27] The total ANR storage/transportation costs recovered through both the annual demand cost and the annual commodity cost is **[TRADE SECRET DATA HAS BEEN EXCISED]**.[28]

A.5.1 ANR Storage/Transport Cost Effectiveness Test

The focus of the Department's analysis of the ANR storage/transportation agreements is the comparison of the total annual costs associated with the five agreements that is recovered the PGA. Due to the ANR transaction's structure, the Department had to calculate the Agreement's cost per

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[21] Petition at 1.
[22] Supplemental filing, **TRADE SECRET** Exhibit A, p. 2.
[23] *Ibid*.
[24] *Ibid.*
[25] *Ibid*.
[26] See **TRADE SECRET** Attachment DOC-5-RC.
[27] *Ibid.*
[28] *Ibid.*

dekatherm of storage to CenterPoint's other existing storage agreements. **TRADE SECRET** Table 1 summarizes CenterPoint's current and proposed storage contracts with outside vendors. The amount of storage, the total annual cost and the maximum daily withdrawal figures are found in the Company's 2025-2026 GPP.[29] The cost per dekatherm (Dth) is calculated by dividing the ANR transaction's total annual cost by the annual amount of storage space provide under the agreement.

The information in Table 1 suggests that the ANR transaction's **[TRADE SECRET DATA HAS BEEN EXCISED]** than CenterPoint's average cost storage calculated without ANR.

The Department considers this result as sufficient to conclude the ANR Agreement is reasonable and recommends the Commission approve it.

TRADE SECRET Table 1 – Comparison of the Cost per Dekatherm of Storage for 2025-2026 Heating Season ($/Dth)

Vendor	Space (Bcf)	Total Annual Cost	Cost per Dth	Max. With. (Dth/Day)
NGPL	**[TRADE SECRET DATA HAS BEEN EXCISED]**			
NNG				
BP Canada				
Tenaska/East Cheyenne #1				
Tenaska/East Cheyenne #2				
ANR				
Total				
Average Cost/Dth - No ANR				

A.6 Seasonal Reservation Fees Update

In CenterPoint's Supplemental filing, the Company updated the supplier demand/seasonal swing reservation fee for the 2025-2026 winter season.[30] This information was estimated when CenterPoint submitted the Petition. CPE explained why it is necessary to update this information in its response to IR 15 in the 2024-2025 demand entitlement filing.

[29] See **TRADE SECRET** Attachment DOC-2-RC, p.19.

[30] Supplemental Filing, Exhibit A, p. 2.

> . . .The Company provides this in its initial request knowing that the fees will change for the upcoming winter; however, at the time of the filing the demand entitlement request, the Company does not have exact fees. Since the request for proposal doesn't occur until late summer, the Company does not have the specifics available for the demand entitlement filing. The Company will submit a supplemental filing in November with the updated fees for swing reservation. [31]

CenterPoint estimated the cost recovered through the demand-delivered cost to be **[TRADE SECRET DATA HAS BEEN EXCISED]** in the Petition.[32] The actual cost identified in the Supplemental filing is **[TRADE SECRET DATA HAS BEEN EXCISED]**.[33] The between the estimate and the actual is a 21% higher amount.

The Department would initiate discovery under most circumstances if it identified a variance of more than 20 percent. In this instance the Department will not pursue additional discovery. The Department is well-acquainted with CPE's process for acquiring its supplier demand/seasonal swing reservation fee for the winter season and the variance between the estimated and actual costs is often over 20 percent.[34] Hence, the Department recommends approval of CenterPoint's proposed supplier demand/seasonal swing reservation fee.

A.7 NNG 2025 Rate Case

The Department also asked CenterPoint to provide additional information on NNG's 2025 rate case. The Company stated in its reply comments.

> On July 1, 2025, NNG filed a $1.1 billion rate case. CenterPoint Energy intervened in the case and is actively participating. The pretrial was held September 11 and top sheets are expected November 6. There is a settlement hearing scheduled for November 20. If no settlement is reached by January 1, 2026, interim rates will go into effect.

The Department appreciates the update CPE provided and will monitor the settlement process as a matter of course.

In the Supplemental Filing, CenterPoint also noted that the filed interim rates included in NNG's FERC rate case will become effective on January 1, 2026. The Company also noted that it was not going to estimate the rate or bill impacts associated with this propose rate change in the supplemental filing. Rather, CPE referred the reader to the Company's upcoming January 2026 PGA filing.

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[31] See **TRADE SECRET** Attachment DOC-6-RC.
[32] *Ibid*., p. 1.
[33] *Ibid*, p. 2.
[34] *Request for a Change in Demand Units*, Department Comments, November 28, 2022, at 9 Docket No. G008/M-22-306 (eDockets) 202211-190912-01 (variance provided in Trade Secret version).

As noted in the Department's Comments, NNG's interim rate request for Market Area Demand rates is equal to an 93 percent rate increase when compared to current rates for the TF 12 Base, TF 12 Variable, TF5 TFX 1 and SMS rate schedules.[35] Given that CenterPoint's proposed current annual demand expense for firm pipeline capacity and other ancillary services is $139.7 million[36], a ninety-three percent across the board increase would equal an increase of $129.9 million in CPE's Annual Estimated Demand Expense (AEDE).[37] Considering the extent of that proposed rate increase on CPE's ratepayers, that change by itself would represent a 67.4 percent increase in annual estimated demand expense.[38] This change would result in an increase in annual demand costs for a small firm customer of $94 annually.[39]

The Department will work with Minnesota's rate regulated gas utilities to understand the effects of different options presented in settlement discussions for NNG's 2025 FERC rate case and work to decrease NNG's proposed increase.

B. TIMING AND MAGNITUDE OF THE 2025-2026 PROPOSED DEMAND COST CHANGES

CenterPoint's 2025-2026 Demand Entitlement filing identified three different dates when demand costs would increase, April 1, May 1, and November 1. The Department discusses the proposed changes to CPE's demand entitlement on each of those dates, and the overall change in the annual demand cost on those dates in the following section. In a subsequent section, the Department considers the proposed overall increase in demand costs and provides some historical context.

B.1 Proposed Demand Cost Changes by Date

B.1.1 April 1, 2025

The Company identified seven changes to its 2025-2026 demand-related entitlement costs effective April 1, 2025, in the Petition.

- The addition of 60 Dth/day of firm capacity year-round on NNG that was the result of an open season for 300 Dth/day. NNG awarded the Company 60 Dth/day out of the 300 Dth/day total.[40]
- The addition of 26,363 Dth/day of summer season capacity on ANR. This capacity is associated with the ANR storage/transport agreement.
- An increase in the negotiated rate the Company pays for the winter season capacity it has on Trailblazer.

[35] Department Comments, DOC Attachment 6, page 13.
[36] Supplemental Filing, Exhibit A at 2.
[37] Calculation equals ($139,722,443 x .93 = $129,941,872).
[38] Calculation equals ($129,941,872/$192,941,872 = 0.67421 or .67.4%).
[39] The annual estimated demand expense for a small firm customer would increase from the current $$1.5333 to $2.586/Dth. Assuming 89 Dths/customer/year the annual demand cost would increase from $136.46 to $230.14 an increase of $93.68.
[40] This addition represents two changes, one for the addition of the winter season capacity and one for the addition of the summer season capacity.

- A minor decrease to the cost of firm storage capacity associated with the Company's contracted FDD. This change in isolation had no financial effect on CPE's AEDE. It was merely a correction.
- Costs for a new firm storage agreement with ANR for 4.5 Bcf of new firm storage.
- Costs for a new firm storage agreement with Tenaska/East Cheyenne for new firm storage for 3.2 Bcf of new firm storage.
- A credit associated with an AMA agreement with Tenaska for CPE's summer season firm capacity on Viking.

The Department estimates that these proposed changes increased the Company's AEDE by **[TRADE SECRET DATA HAS BEEN EXCISED].**[41]

B.1.2 May 1, 2025

The Company identified one change to its 2025-2026 demand-related entitlement costs effective May 1, 2025, in the Petition. The initiation of an agreement with BP Canada for firm storage service.[42] This agreement replaced a similar agreement for marketer firm storage service which expired on April 30, 2025.

The Department estimates that this proposed change increased the Company's AEDE by **[TRADE SECRET DATA HAS BEEN EXCISED]** after netting off the cost of the expired agreement**.**[43]

B.1.3 November 1, 2025

The Company identified four changes to its 2025-2026 demand-related entitlement costs effective November 1, 2025, in the Petition.

- The initiation of three separate agreements for firm pipeline capacity associated with the ANR storage/transport agreement.[44]
- Costs related to the 2025-2026 winter season swing gas agreements.[45]

The Department estimates that these proposed changes increased the Company's AEDE by **[TRADE SECRET DATA HAS BEEN EXCISED]** after netting off the cost of the expired agreement.[46]

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[41] See **TRADE SECRET** Attachment DOC-7-RC.
[42] This agreement essentially was a continuation of a similar agreement for marketer firm storage service which expired on April 30, 2025.
[43] The total annual costs associated with the BP Canada agreement are **[TRADE SECRET DATA HAS BEEN EXCISED]** of which **[TRADE SECRET DATA HAS BEEN EXCISED]** are recovered through the AEDE.
[44] These new agreements were for 50,690 Dth/day of annual FT-1 Transport capacity, and two agreements for annual of FT-3 Transport capacity of 25,345 Dth/day each. The total increase firm capacity on ANR resulting from the three agreements is estimated to be 101,380 Dth/day.
[45] CenterPoint incurs these costs annually.
[46] The total annual costs associated with the BP Canada agreement are **[TRADE SECRET DATA HAS BEEN EXCISED]** of which **[TRADE SECRET DATA HAS BEEN EXCISED]** are recovered through the AEDE.

The sum of the proposed incremental cost increases effective April 1, May 1 and November 1, 2025, is **[TRADE SECRET DATA HAS BEEN EXCISED].**[47]

B.2 Effects of Proposed Changes in the Annual Demand Cost by Rate Schedule

The Company provided estimates of the effects of the proposed increases in demand costs on April 1, May 1, and November 1 in the Amended Petition and its Supplemental Filing. The Department re-created that analysis, and it is included as Department Exhibit 2.a through 2.d. The results of the Department's analysis were consistent with CenterPoint's results.

B.2.1 April 1, 2025

CenterPoint's proposed changes effective April 1, 2025, would result in the following increases in the annual demand cost by rate schedule compared to the rates included in the March 2025 PGA:

Table 2.a: Annual Demand Cost Impact by Rate Schedule Effective April 1, 2025, Compared to March 1, 2025, PGA[48, 49]

Rate Schedule	Annual Usage (Dth/yr.)	Annual Demand Cost Change ($)	Percentage Change
Residential	89	$5.11	3.97%
Comm/Ind. Firm A	81	$4.65	3.97%
Comm/Ind. Firm B	730	$41.90	3.97%
Comm/Ind. Firm C	12,076	$693.14	3.97%
Large General Service	47,751	$20,950.93	22.84%[50]

The $5.11 increase in the annual demand cost for a residential customer demonstrates extent of the proposed increases to the annual demand cost recovered by the PGA as of March 1, 2025. This results in an increase of 3.97 percent in the annual demand cost a residential customer will pay.

B.2.2 May 1, 2025

CenterPoint's proposed changes effective May 1, 2025, would result in the following annual impacts compared to the demand costs included in the April 2025 PGA:

Table 2.b: Annual Demand Cost Impact by Rate Schedule Effective May 1, 2025, Compared to April 1, 2025, PGA[51]

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[47] See **Trade Secret** Attachment DOC-7-RC.
[48] Supplemental Filing, Exhibit B4.
[49] See Department Exhibit 2.a.
[50] The increase in the annual demand cost of almost $21,000 and 23 percent highlights the effects of the proposed increases to a customer class that has a separate demand charge. The annual cost increase and percentage increase would be even higher if the Average Daily MDQ used in the March 2025 PGA versus the Average MDQ used in April 2025 PGA were identical. The Average MDQ decreased by 1,298 Dth. in April 2025 from 8,448 Dth to 7,150 Dth.
[51]

Rate Schedule	Annual Usage (Dth/yr.)	Annual Demand Cost Change ($)	Percentage Change
Residential	89	$3.97	2.97%
Comm/Ind. Firm A	81	$3.61	2.97%
Comm/Ind. Firm B	730	$32.56	2.97%
Comm/Ind. Firm C	12,076	$538.57	2.97%
Large General Service	47,751	$3,351.21	2.97%

Like the results from the March to April comparison, higher demand costs result in an increase in the annual demand cost and an almost 3 percent increase on an annual basis.

B.2.3 November 1, 2025

CenterPoint's proposed changes effective November 1, 2025, result in the following annual impacts compared to the demand costs included in the October 2025 PGA:

Table 2.c: Annual Demand Cost Impact by Rate Schedule Effective November 1, 2025, Compared to October 1, 2025, PGA[52, 53]

Rate Schedule	Annual Usage (Dth/yr.)	Annual Demand Cost Change ($)	Percentage Change
Residential	89	($1.16)	-0.84%
Comm/Ind. Firm A	81	($1.05)	-0.84%
Comm/Ind. Firm B	730	($9.49)	-0.84%
Comm/Ind. Firm C	12,076	($156.98)	-0.84%
Large General Service	47,751	$643.50	0.55%

The decrease in the annual demand cost change for the residential and commercial classes in Table 2.c is not consistent with the increased costs CPE is requesting to recover in that update. The reason for this counter-intuitive result is that the Company increased the number of billing determinants for the Annual Small Firm Demand Volume in the November 2025 calculation. The number of billing determinants increased from 1,195,457,049 to 1,247,845,315 due to the Commission's approval of CPE's 2023 general rate case. This change didn't affect the billing determinants for the Large General Service class and correspondingly, a customer with average usage in that class would have seen an increase in their annual demand costs of $644 or 0.55 percent.

B.2.4 Comparison of Total Change in the Annual Demand Cost by Rate Schedule – April -November 2025

[52] 2025 November Update, Exhibit B4.
[53] See Department Exhibit 2.c.

This comparison that provides an estimate of the overall increase to the annual demand cost of CenterPoint's proposed changes effective November 1, 2025, which would result in the following annual rate impacts compared to the rates included in the March 2025 PGA:

Table 2.d: Annual Demand Cost Impact by Rate Schedule Effective November 1, 2025, Compared to March 1, 2025, PGA[54]

Rate Schedule	Annual Usage (Dth/yr.)	Annual Demand Cost Change ($)	Percentage Change
Residential	89	$7.92	6.16%
Comm/Ind. Firm A	81	$7.21	6.16%
Comm/Ind. Firm B	730	$64.97	6.16%
Comm/Ind. Firm C	12,076	$1,074.73	6.16%
Large General Service	47,751	$24.945.64	27.20%

Table 3 compares the nominal and percentage changes for each of the last 10 years in CenterPoint's Annual Estimated Demand Expense. This comparison helps place the Company's proposed increase in an historical context.

Table 3: Annual Demand Cost Expense Effective November 1, Compared to Prior Year, 2016-2025

Line No.	Docket No.	Heating Season	AEDE	$ Variance from Prior Yr	% Var.
1.	16-571	2016-2017	$87,257,510	NA	NA
2.	17-533	2017-2018	$86,801,411	($456,099)	-0.5%
3.	18-462	2018+2019	$95,373,796	$8,572,385	9.9%
4.	19-278	2019-2020	$121,011,159	$25,637,363	26.9%
5.	20-565	2020-2021	$127,714,971	$6,703,812	5.5%
6.	21-523	2021-2022	$154,941,631	$27,226,660	21.3%
7.	22-306	2022-2023	$155,513,369	$571,738	0.4%
8.	23-221	2023-2024	$167,812,080	$12,298,711	7.9%
9.	24-146	2024-2025	$173,965,593	$6,153,513	3.7%
10.	25-72	2025-2026	$192,732,049	$18,766,456	10.8%
11.	Average			$11,719,393	
12.	Total Nominal Change 2016-2025			$105,474,539	120.9%
13.	Number of Years				10
14.	Average Percentage Change				12.1%

At 10.8 percent, the year-to-year increase in the AEDE is the third largest increase in the past ten years. This result concerned the Department. However, after reviewing the November 2025 AEDE more

[54] See Department Exhibit 2.d

closely, the Department noticed that CenterPoint increased the amount of physical storage under contract by **[TRADE SECRET DATA HAS BEEN EXCISED]** which was responsible for **[TRADE SECRET DATA HAS BEEN EXCISED]** of the $18.8 million increase in AEDE.

In terms of CPE's overall storage quantity, these changes increase that category by 9.0 percent in the 2025-2026 Winter plan compared to the 2024-2025 Winter plan. The Department considers the increase in storage capacity to be reasonable after reviewing generally available supply and demand information on the interstate pipeline system.

For example, the American Gas Association (AGA) published a report titled "Assessing the Value of Storage of Natural Gas Storage" in April 2025.[55] In the Executive Summary of that document, the AGA lists Tempering Price Volatility" one of the roles that natural gas storage plays in the U.S. energy system. Specifically,

> Storage provides a key physical and financial asset that helps reduce consumer exposure to volatile prices and allows for market participants to contribute to a robust and liquid natural gas market. . . . Storage adds flexibility and optionality for market participants that can stabilize prices and reduce price risk for consumers.[56]

CenterPoint incurred approximately $408 Million in extraordinary gas costs over a four-day period in February 2021 (Storm Uri) of which the Commission allowed it to recovery $372.4 million.[57] As a result of that event, the Commission directed the Company to work towards minimizing its ratepayers' exposure to extraordinary natural gas price spikes in the future. Physical storage is an important way to minimize that sort of risk.

Hence, the Department concludes CenterPoint is pursuing a strategy consistent with the Commission's directive and recommends the Commission approve CenterPoint's request for the costs identified in the Petition.

IV. RECOMMENDATIONS

Regarding the topics/issues reviewed in these response comments, the Department recommends the Commission approve the following proposed changes to CPE's 2025-23026 Winter season Demand Entitlement:

- NNG – TFX Northern Lights 2025
- Tenaska/CenterPoint Asset Management Agreement (AMA)
- Trailblazer rate increase
- Viking Firm Capacity Renewal
- ANR Transport/Storage Agreement

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[55] See Attachment DOC-1-RC.
[56] *Ibid*, p. 2.
[57] *In the Matter of the Petition of CenterPoint Energy for Approval of a Recovery Process for Cost Impacts Due to Extreme Gas Market Conditions,* PUC Order, October 19. 2022, Docket No. G008/M-21-138 at Order Points 2-5 and 10.

- Swing reservation fees identified in the Company's November 1, 2025.

In its comments filed September 16th in this docket, the Department also recommended the Commission approve:

- The NNG-Carlton South agreement.
- The Tenaska/East Cheyenne storage agreement.
- The new marketer storage agreement with BP Canada.
- The proposed correction to the FDD annual cost.

The Department is not recommending any modifications or rejections of any of CPE's proposed changes to its Demand Entitlement. Hence, the Department recommends the Commission approve CenterPoint's proposed demand cost recovery proposal.

Relative to CenterPoint's proposed changes to items other than its Demand Entitlement but relevant to this docket, the Department recommends the Commission:

- Accept CenterPoint's proposed estimated 2025-2026 design-day.
- Not adjust CPEs proposed 2025-2026 design day analysis for the effects of electrification/decarbonization.
- Accept CenterPoint's 2025-2026 reserve margin.
- Find that CenterPoint has met the annual reporting requirements included in the 21-102 and 21-138 dockets.
- Take no action on the Company's request for variance to Minnesota R. 7825.2910 Subpart 2.

The Department is not forwarding a recommendation regarding CPE's distribution planning assumptions for the 2025-2026 period. The reason for this change is that CenterPoint is currently developing a natural gas integrated resource plan (IRP) which is scheduled to be filed July 1, 2027.[58]

The Department reviewed this issue largely due to concerns in other dockets regarding distribution investment in past demand entitlement filings. The Gas IRP process specifically reviews the need for additional distribution investment. Hence, the Department's position is that this issue will be addressed in the IRP process on a forward-looking basis.

[58] *In the Matter of a Commission Investigation into Gas Utility Resource Planning,* PUC, Order Clarifying and Expanding Framework for Natural Gas Integrated Resource Planning, October 28. 2024, Docket No. G008/M-23-117 at Order Point 22.a.

Attachments

Title	Description	Topic
DOC-1-RC	American Gas Association Value of Storage Report	Storage
TRADE SECRET DOC-2-RC	CPE 2025-2026 Gas Procurement Plan (GPP)	2025-2026 Procurement Plan
DOC-3-RC	Email on 2025 Northern Lights CIAC Payment	Firm Pipeline Capacity Costs
TRADE SECRET DOC-4-RC	DOC IR No. 31	CenterPoint/Tenaska AMA
TRADE SECRET DOC-5-RC	ANR Storage and Transportation Annual Costs	Storage
TRADE SECRET DOC-6-RC	DOC IR No. 15/Company response from Docket No. 24-146	Timing of Swing Gas RFPs
TRADE SECRET DOC-7-RC	Effects of Changes to Annual Demand Costs on April 1, May 1, and November 1, 2025	Proposed Changes to Demand Expense by Date

Exhibits

Title	Description	Topic
DOC-1	Updated Reserve Margin	Demand Entitlement
DOC-2.a	Changes to Annual Demand Cost Effective April 1, 2025	Changes to Annual Demand Cost by Rate Schedule
DOC-2.b	Changes to Annual Demand Cost Effective May 1, 2025	Changes to Annual Demand Cost by Rate Schedule
DOC-2.c	Changes to Annual Demand Cost Effective Nov 1, 2025	Changes to Annual Demand Cost by Rate Schedule
DOC-2.d	Potential Change to Annual Demand Cost from NNG 2025 FERC Rate Cast Effective January 1, 2026	Changes to Annual Demand Cost by Rate Schedule

American Gas Association

Assessing the Value of Natural Gas Storage

A Strategic Asset for Grid Reliability, System Resilience, and Operational Flexibility in a Changing Energy Landscape

April 29, 2025

Prepared By

Liz Pardue | Director, Economic and Regulatory Analysis | lpardue@aga.org | 202-824-7214
Lauren Scott | Market and Regulatory Analyst | lscott@aga.org | 202-824-7152
Energy Markets, Analysis, and Standards

American Gas Association
400 N. Capitol St. NW
Washington, DC 20001
www.aga.org

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Table of Contents

Table of Figures

Table of Tables

American Gas Association

Executive Summary

Natural gas storage is a critical pillar of the U.S. energy system, enabling gas to be stored when demand is low and withdrawn when demand is high. This flexibility helps provide reliable and affordable energy delivery year-round to homes, businesses, and power generators and for delivery to other markets. Storage plays a key role in maintaining system balance, flexibility, and resilience in a market shaped by seasonal variability, extreme weather, and shifting consumption patterns. As the U.S. economy becomes increasingly energy-intensive, driven by new consumers, growing electric demand, digital technologies, artificial intelligence, and global trade, natural gas continues to serve as a stabilizing force in a more dynamic and demanding energy environment.

At the heart of this evolving landscape lies the natural gas storage network, which spans a range of technologies including underground storage in depleted oil and gas reservoirs, aquifers, and salt caverns, as well as liquefied natural gas (LNG) and compressed natural gas (CNG) storage. These resources not only help meet seasonal fluctuations and short-term surges in demand but also provide critical backup during unplanned disruptions. Many storage facilities are strategically co-located with baseload and peaking electricity generation sites to enhance supply flexibility and grid reliability. Storage supports a diverse set of market participants, including pipeline operators, local distribution companies (LDCs), electric utilities, and independent operators, by ensuring continuity of service and stabilizing prices in volatile market conditions. Market participants utilize storage for supply and optionality.[1] Ultimately, natural gas storage is a key component of the U.S. energy system that contributes to a diverse market and promotes reliable access to supply.

This report provides a comprehensive review of the current state and strategic importance of U.S. natural gas storage. It explores the value storage brings to the broader energy value chain and outlines the regulatory frameworks that govern it, including oversight from federal and state regulators. It also highlights emerging challenges and outlines the policy steps necessary to secure the role of storage in a rapidly transforming energy landscape. As energy systems grow more complex, natural gas storage will remain a vital asset to help ensure energy security, reliability, and affordability for the nation.

Storage is a Critical Component of the Energy System

Natural gas storage plays many roles in the U.S. energy system:

- **Balancing Seasonal Demand:** Storage enables producers and utilities to inject gas during low-demand months and withdraw it during winter heating or peak cooling periods. This seasonal flexibility is essential to ensure uninterrupted service and avoid costly infrastructure expansion.
- **Tempering Price Volatility:** Storage provides a key physical and financial asset that helps reduce consumer exposure to volatile prices and allows for market participants to contribute to a robust and liquid natural gas market. Merchant operators[2] may release gas when prices rise, boosting supply and

[1] In this context, optionality refers to the flexibility and strategic choices that natural gas storage provides to market participants.
[2] Merchant operators are private companies or entities that own gas in storage for commercial, profit-driven purposes rather than for regulatory, utility, or system-balancing obligations.

easing market pressure. Utilities often draw from storage to maintain reliability. In both cases, storage adds flexibility and optionality for market participants that can help stabilize prices and reduce price risk for consumers.

- **Providing Emergency Support:** Storage enhances system reliability and resilience during extreme events, such as hurricanes, polar vortices, wildfires, and pipeline outages. During Winter Storm Enzo on January 21, 2025, underground storage withdrawals reached a new record. In prior years, such as during Winter Storm Uri in 2021, nearly 340 Bcf was withdrawn in a single week—the second-largest draw in U.S. history. This source of supply may have mitigated service interruptions and price shocks**.**
- **Enabling Grid Flexibility and Renewable Integration:** As variable renewable electricity generation grows, natural gas storage provides a vital complement to enhance grid reliability by enabling more fuel on demand to natural gas-fired generators, particularly during times of pipeline constraint or disruption to other flowing supplies. Storage also offers fast-ramping, long-duration energy that can respond when renewable output dips. On January 21, 2025, storage withdrawals delivered nearly 21,100 GWh, 144 times the daily output of all U.S. pumped hydro and battery storage combined, demonstrating gas storage's unmatched scale and flexibility in supporting grid stability.

These benefits are increasingly valuable as electricity demand rises, particularly with the growth of data centers, industrial facilities, and new residential development. Natural gas storage ensures the system remains flexible in the face of this growth, delivering energy where and when it is needed most.

Emerging Pressures on Storage Infrastructure

There is a growing need for more gas infrastructure, including pipelines and storage. In recent years, U.S. natural gas production, pipeline capacity, and demand have all grown significantly, yet underground storage capacity additions have remained mostly flat. From 2014 to 2023, underground storage capacity grew at just 0.1 percent per year, down from 1 percent annually between 2000 and 2013. In contrast, LNG storage capacity more than doubled between 2021 and 2023, growing from 28.3 Bcf to 67.3 Bcf, largely driven by export growth and expanded use in areas without underground infrastructure.

The value of storage today is increasingly tied to its flexibility, optionality, and responsiveness, and that value has grown more important given today's current market trends. In several regions, notably the East, Midwest, and Mountain states, underground storage utilization has approached or exceeded 90 percent on average heading into the winter heating season over the past five years. However, increased price volatility in recent years may signal a growing need for more storage or a growing mismatch between infrastructure capacity and demand, especially if natural gas demand continues to grow at a pace that exceeds the necessary infrastructure and storage capacity additions. Between 2015 and 2019, daily Henry Hub price volatility averaged 43 percent; that figure rose to 71 percent between 2020 and 2024. Storage provides a physical and financial hedge to reduce risk against this volatility, enabling system operators and market participants to act in fast-changing conditions.

At the same time, the traditional economic valuation of storage has shifted. The simplest form of storage value is based on seasonal price spreads and optionality afforded by storage holders to provide physical and financial services to the market. However, the shape of the seasonal price curve has changed with evolving gas demand requirements, particularly in the electric power sector. Those seasonal price differences have narrowed with more gas consumed year-round, especially by power plants during the summer. Between 2013 and 2023, the average price spread was negative, at -$0.38 per MMBtu. In comparison, average spreads were positive in earlier decades. For example, between 1994 and 2003, the average spread was $0.22 per MMBtu.

Capacity Constraints, Delivery Challenges, and Planning Gaps

While storage facilities have proven their value during high-impact events, several structural and regulatory barriers continue to limit the system's overall effectiveness:

- **Storage capacity[3] constraints** limit the volume of gas that can be stored in regions where demand is rising, especially as electric generation increasingly relies on gas-fired capacity during both summer and winter peaks.
- **Limited withdrawal rates** can restrict how quickly gas can be deployed, particularly in older facilities or in areas with few pipelines or constrained pipeline capacity. This can lead to regional service bottlenecks during high-demand periods and lower optionality for storage providers to provide services to the broader market.
- **Project development timelines** remain long. Regulatory reviews, permitting processes, and inter-agency coordination requirements can add years to storage projects, discouraging investment and limiting responsiveness.
- **Market signals** do not always reflect the full range of storage benefits, especially for regulated entities that cannot recover value based on flexibility or grid support due to current market rules.

Despite these challenges, market fundamentals suggest the need for proactive storage expansion. The U.S. became the largest LNG exporter in 2023, averaging 11.2 Bcf per day of export volume. Domestic gas consumption, driven primarily by industrial activity and electric demand tied to data center growth, is also forecast to rise. In regions like the South Central, Mountain, and East, some additional storage is already being developed, but new projects have yet to materialize in other regions.

Policy Considerations and Strategic Action

To support energy reliability, affordability, and security, natural gas storage must be treated as a strategic infrastructure priority. That means recognizing its value, planning for its future, and ensuring the regulatory and investment frameworks are aligned with long-term system needs.

Key Considerations Include:

- **Targeted Expansion:** Storage capacity is approaching practical limits in several high-demand regions. Strategic investments in new underground and LNG facilities[4] will be essential, particularly where

[3] Natural gas storage capacity with respect to linepack is discussed in further detail in Section 2.
[4] LNG facilities are complexes designed to handle LNG and can vary by use. Types of LNG facilities are described in Section 2 and summarized in Table 2.

capacity utilization averages at or above 90 percent. These investments should align with growing residential loads, increased industrial consumption, and power sector needs.

- **Faster, Clearer Project Approvals:** Storage projects require years to move from concept to completion. Regulatory clarity and streamlined permitting can help remove bottlenecks and allow projects with broad system benefits to move forward more efficiently.
- **Improved Integration with Energy Planning:** Storage is not always considered in broader conversations about reliability, clean energy, or infrastructure planning. Including natural gas storage in state and regional energy plans will help ensure it is available when needed, particularly as grid flexibility becomes more important.
- **Recognition of Storage's Full Value:** Storage provides more than economic returns; it contributes to reliability, resilience, emergency preparedness, and consumer protection. These broader benefits should be reflected in how storage is valued in policy, regulation, and energy markets.
- **Support for Low-Carbon Pathways:** Current and future natural gas storage expansion supports and enables pathways to lower greenhouse gas emissions. By enhancing energy system flexibility, storage aids in the growth of renewable energy. Underground storage facilities can be utilized for renewable natural gas storage, enabling greater seasonal use. Additionally, natural gas storage could be repurposed for hydrogen-ready capabilities in future scenarios.

Regional and local market analysis could identify areas where new storage capacity may provide strategic value and reveal how market participants value existing storage assets. Quantifying differences between observed storage rates and theoretical benchmarks based on market pricing can highlight regional or local market opportunities for investment and help optimize storage capacity. Such analysis also sheds light on how operators today and in the future value storage optionality, flexibility, and reliability across various regions, providing insights critical to both commercial strategy and informed policymaking.

Beyond price signals, regional analysis can also quantify the broader "resilience dividend" that storage delivers. Stress-testing local demand and supply against extreme-weather scenarios, pipeline outages, and rapid renewable ramping reveals how incremental storage capacity can fortify reliability, support renewable integration, and protect consumers—insights that are essential for both commercial strategy and forward-looking energy policy.

Natural gas storage is a national asset that supports millions of customers, stabilizes markets, and protects energy delivery through routine operations and extraordinary events. As the U.S. energy system continues to evolve, the value of storage will only grow. Ensuring its continued reliability and flexibility is critical to maintaining a secure and resilient energy system.

1. Introduction

Natural gas is among the most flexible and dependable energy resources, essential for heating, electricity generation, and industrial processes across the country. The natural gas system delivers nearly three times more domestic energy during the winter heating season than the electric grid during summer peaks on average. Its reliability and value, however, significantly depend on infrastructure to store and deliver natural gas effectively and strategically.

Natural gas storage helps to ensure the operational flexibility, efficiency, and resilience of the U.S. energy system. By bridging the gap between continuous natural gas production and variable demand, storage enables reliable service across days and seasons, and in response to unanticipated disruptions. As the U.S. energy landscape evolves amid changing markets, technological innovation, regulatory developments, and global trends, a comprehensive understanding of natural gas storage, from basic infrastructure to market valuations and operations, has never been more important.

For over a century, the U.S. has stored natural gas underground in aquifers, salt caverns, and depleted reservoirs for on-demand market needs. Technology advancements through the 20th century introduced liquefied natural gas (LNG) and compressed natural gas (CNG), resulting in even more versatile, compact, and transportable storage options.

Purpose of the Report and Content Overview

This report provides a comprehensive overview of U.S. natural gas storage, exploring its technical foundations, market structure, strategic value, and future challenges. The discussion begins with an examination of storage fundamentals, highlighting its history, mechanics, and capabilities.

The report is separated into five core sections and conclusions:

- **Section 2. Storage Basics** discusses the history and development of natural gas storage and how natural gas is stored today.
- **Section 3. Market Landscape and Participants** describes the market participants utilizing and benefiting from natural gas storage and the jurisdictional considerations surrounding regulation and oversight of natural gas storage facilities.
- **Section 4. Seasonality, Reliability, and Resiliency** describes the ways in which natural gas storage contributes to the reliability and resiliency of the grid and how natural gas storage supports market stability in seasonal weather patterns.
- **Section 5. Value of Storing Natural Gas** details the intrinsic and extrinsic valuation of investment in natural gas storage.

- **Section 6. Constraints, Challenges, and Future Outlook** examines the current and future challenges facing natural gas storage and explores the need for regional expansion and strategic investment in response to evolving market pressures.
- **Section 7. Conclusions** emphasizes that storage capacity, infrastructure, and technology investments are essential to ensure that the U.S. can maintain a stable, reliable, and resilient energy system and strategically plan for future growth.

Additionally, Appendices A and B provide abbreviations and a glossary of terms, respectively, for the reader's reference.

To ground this discussion, the report begins by outlining the foundational elements of natural gas storage via the history, development, and current practices of storing natural gas in the U.S. This context establishes the technical baseline essential for understanding the broader operational, economic, and strategic themes addressed in the subsequent sections.

2. Storage Basics

Natural gas storage is foundational to energy system stability and efficiency, allowing operators to balance consistent supply against fluctuating demands. In this section, we first highlight recent capacity trends in both underground and LNG storage, then dive into the mechanics and performance metrics of underground facilities (cushion vs. working gas, deliverability, and injection rates), and finally survey supplemental options such as LNG terminals, linepack, and CNG.

To set the stage, recent EIA data highlight shifts in both underground and LNG storage capacity across the U.S. According to the Energy Information Administration (EIA), the demonstrated peak capacity[5] of underground storage in the lower 48 states increased by 3 percent to just over 4,200 billion cubic feet (Bcf) in the November 2023 reporting period after three consecutive years of falling demonstrated peak capacity.[6] Additionally, the U.S. reported the seventh largest net LNG storage addition of nearly 8 Bcf in 2023, after a net withdrawal of approximately 3.5 Bcf the year prior. Storing natural gas for future use provides a vital and reliable backup source for balancing supply disruptions, transmission pipeline issues, and unexpected peaks in demand so that

[5] Demonstrated peak capacity refers to the sum of the largest volume of working natural gas reported for each individual storage field during the most recent five-year period, regardless of when the individual peaks occurred.

[6] The EIA releases annual Underground Natural Gas Working Storage Capacity reports. The November 2023 reporting period encompasses data from December 2018 through November 2023. The next report is expected to be released in April 2025. For more information, visit https://www.eia.gov/naturalgas/storagecapacity/.

Note: The EIA calculates demonstrated peak capacity using individual operator data reported in the monthly 191 form. The most recent update is for November 2023. This report is released separately from their annual 191 publication, which was updated on December 2024 for the 2023 year.

The EIA Form EIA-191, Monthly Underground Gas Storage Report, provides data on the operations of all active underground storage facilities. Data are collected and mandated under the Federal Energy Administration Act of 1974, Public Law 93-275 and appear in EIA publications such as the annual field-level storage report and the demonstrated peak capacity report.

natural gas customers receive the reliable service they have come to expect. This section provides an overview of storage fundamentals to better understand the value natural gas storage offers.

Underground Natural Gas Storage

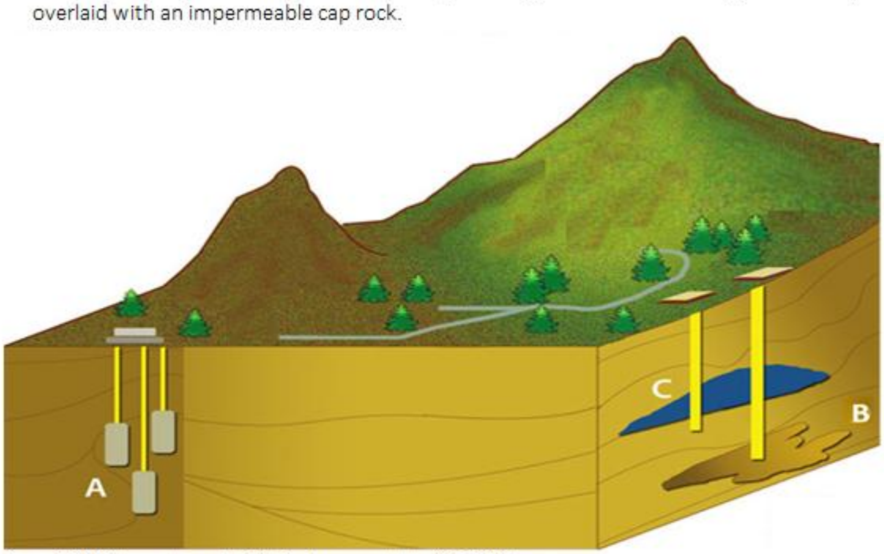
The beginning of natural gas storage dates to the early 20th century. In 1915, the first successful underground storage project was completed in Welland County, Ontario, and the following year, the first U.S. facility began operating in the Zoar gas field south of Buffalo, New York.[7] Through the 1930s, underground gas storage was primarily located in depleted oil or natural gas fields. Opportunities in geological storage development led to the use of aquifers and salt caverns between the 1940s and 1960s.[8] Today, most underground storage in the U.S. is found in depleted oil or natural gas fields that are closely located to pipelines, electric generation facilities, and natural gas markets.

Today, there are three types of underground storage facilities: salt caverns, depleted natural gas or oil fields, and aquifers. Figure 1 describes and illustrates each storage facility type.

Figure 1: Types of Underground Natural Gas Storage Used in the U.S.

Three main types of natural gas underground storage facilities used in the U.S.

A. **Salt caverns** - Mostly developed in salt dome formations located in the Gulf Coast states. Salt caverns have also been leached from bedded salt formations in states in the Midwest, Northeast, and Southwest.
B. **Depleted natural gas or oil fields** - Most of the existing natural gas storage in the U.S. is in depleted natural gas or oil fields located close to consumption centers.
C. **Aquifers** - Most notably in the Midwest, natural aquifers have been converted to natural gas storage reservoirs. An aquifer is suitable for natural gas storage if the water bearing sedimentary rock formation is overlaid with an impermeable cap rock.



Source PB-KBB, Inc., enhanced by EIA, further amended by AGA (2016)

7 https://www.ferc.gov/industries-data/natural-gas/overview/natural-gas-storage/natural-gas-storage-background
8 https://archives.datapages.com/data/phi/v17-2016/arthur-alleman-andersen.htm

The location of different underground storage field types depends on local geology and market access. Generally, most aquifers are located in the Midwest, with some also located in the West. By contrast, most salt caverns are located in the Gulf States. Depleted natural gas and oil fields repurposed for underground natural gas storage are found in many areas of the country.

Pressure plays a critical role in the maintenance and operation of storage facilities. All underground storage contains cushion gas and working gas. Cushion gas is the gas that remains in the storage reservoir as permanent inventory for a facility and is necessary to maintain adequate pressure and deliverability rates during the withdrawal season. Conversely, working gas is the natural gas actively being used for storage and withdrawal to meet customer demand. By extension, working gas capacity is the amount of gas at a facility that can be injected into the transmission or distribution system for use by customers, and is equal to the total maximum volume that a storage facility holds at any one time minus the cushion gas.[9]

In practical terms, the volume of working gas and these pressure-driven characteristics in the reservoir form the basis for contractual "ratchet" provisions, which shape the maximum allowable injection or withdrawal rates under the terms of a storage tariff agreement. The deliverability rate (*i.e.*, the amount of gas that can be withdrawn in one day) is highest when the facility is full and declines as gas is removed. A facility's injection rate is inverse to the deliverability rate, increasing as storage reserves deplete.[10] Cushion gas, working gas capacity, deliverability rates, and injection rates will vary between facilities, making ratchets essential to aligning contractual entitlements with the physical realities of underground storage.

The abilities and limitations of different types of facilities are listed in Table 1.

[9] https://www.eia.gov/naturalgas/storage/basics/
[10] *Id*.

Table 1: Overview of Underground Natural Gas Storage Types

	Description	Abilities	Limitations
Depleted Fields	• Formations that have been depleted of natural gas or oil resources, leaving behind underground fields capable of holding and storing natural gas • To maintain pressure in depleted reservoirs, approximately 50 percent of the gas must be left as cushion gas	• Large capacity • Geographical availability	• Low deliverability rates • Slow cycling
Aquifers	• Underground porous, permeable rock formations that act as natural water reservoirs • Cushion gas requirements can be between 50 to 80 percent of the total gas volume to maintain pressure	• High deliverability rates • Geographical flexibility • Large capacity potential	• Complex operation • Lower efficiency
Salt Caverns	• Formed from existing gas deposits, either salt domes or salt beds • Requires only 20 to 30 percent of total capacity to be used as cushion gas	• High deliverability rates • Fast cycling	• Limited total capacity

Source: FERC Natural Gas Storage – Storage Fields[11]

[11] https://www.ferc.gov/industries-data/natural-gas/overview/natural-gas-storage/natural-gas-storage-storage-fields

American Gas Association

Liquefied Natural Gas Storage


Above-Ground LNG Storage Tanks
Source: U.S. Department of Energy

The process of storing LNG in the U.S. began a few years after the opening of the Zoar underground storage facility in Buffalo, New York. The first LNG plant began operation in 1917 in West Virginia, followed by the first commercial plant in 1939.[12] The liquefaction process requires cooling the gas molecules to around -260° Fahrenheit. The volume of LNG is about 600 times smaller than natural gas in its gaseous state, which helps improve storage and shipment efficiency.[13] Today, LNG is most commonly stored at import or export terminals, peaker plants, or satellite facilities.

At each of these storage sites, liquified gas is stored in single, double, or full containment systems that use auto-refrigeration to keep the tank's pressure and temperature constant.[14] LNG tanks can be constructed above or below ground, and depending on the type of facility, natural gas may be liquefied on-site or delivered to the storage facility via LNG transportation. LNG is typically transported using specially designed tank trucks, International Organization for Standardization (ISO) containers, and tanker or carrier ships.[15] Table 2 lists the facility types, features, and purposes in greater detail.


Liquefied Natural Gas (LNG) Cargo Ship
Source: U.S. Department of Energy

[12] National Association of State Fire Marshals. (2005). *Liquefied Natural Gas: An Overview of the LNG Industry for Fire Marshals and Emergency Responders. https://primis.phmsa.dot.gov/comm/publications/lng_for_fire_marshals_06-2005.pdf*
[13] https://www.energy.gov/fecm/liquefied-natural-gas-lng
[14] https://www.matrixpdm.com/an-introduction-to-lng-storage-systems
[15] https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-facility-siting

Table 2: Overview of LNG Storage Facilities

	Description	Features
Import and Export Terminals	• LNG is stored in large-scale tanks before regasification[16] or shipment via specialized tanker ships • Export terminals: liquefaction capabilities • Import-only terminals: regasification capabilities	• Supply management • Demand support • Reduced market volatility
Peaker Plant	• LNG is stored in tanks connected to gas transmission or distribution pipelines for demand management • Gas is typically liquefied when demand is low and vaporized[17] for distribution when demand peaks to alleviate the load on the system • Most facilities are designed to provide five to 15 days of supply at the maximum send-out rate and refill in approximately 200 days[18]	• Includes liquefication and regasification capabilities • Seasonal demand management • Enhanced reliability • Strategically located in the pipeline system • Cost management
Satellite Facilities or Satellite Plants	• Serve the same function as peaker plants, but do not have liquefication capabilities • LNG is delivered to the site via tanker trucks	• Seasonal demand management • Enhanced reliability • Cost management

Source: PHMSA LNG Facility Siting[19]

Increasingly, LNG storage can also be co-located with electric power plants. Natural gas flows at a rate of around 20 to 30 miles per hour, depending on linepack[20] conditions, so co-location helps optimize pipeline capacity[21] and improve reliability for electricity producers and consumers of electricity and natural gas.[22] Pipeline capacity optimization, service reliability, and mobile or temporary LNG facilities are important considerations for the strategic deployment of LNG and the location of peak shaving[23] and satellite facilities along the gas distribution system.

[16] Regasification refers to the process of converting LNG back to its gaseous form.
[17] Vaporization is a step within the regasification process where a liquid physically changes to a gas.
[18] https://ingaa.org/wp-content/uploads/2014/05/21698.pdf
[19] https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-facility-siting
[20] Linepack refers to the amount of gas stored in the pipes of the gas transmission or distribution system.
[21] Pipeline capacity is the maximum volume of gas that can flow through a pipeline at one time.
[22] https://www.energy.gov/sites/prod/files/2015/04/f21/AttachB_Aspen_GasStorage2012.pdf
[23] Peak shaving is a strategy that aims to reduce energy usage during periods of peak demand to promote energy system integrity and resilience. Peak shaving can take many forms, including demand response, energy efficiency, interruptible service, and, in the case of the electric grid, direct use natural gas service.

Mobile or temporary LNG facilities are small-scale and portable. They deliver gas directly to a pipeline for peak-shaving purposes or pressure maintenance during pipeline repair or assessment. Often, these facilities do not have storage capabilities and rely on LNG trucks for supply.[24]

Floating Storage Units (FSUs), or Floating Storage and Regasification Units (FSRUs), are another form of LNG storage used by the offshore industry and at LNG import and export terminals. FSUs are ships or barges that combine LNG storage with built-in regasification systems (in the case of FSRUs).[25] Old LNG carriers and tankers can be converted to FSUs and FSRUs, which shorten lead times and reduce costs. For this reason, floating storage solutions are becoming increasingly popular and are expected to play an important role as LNG technology continues to develop.[26]

Other Storage Options

In addition to underground and LNG storage, the natural gas system utilizes supplemental forms of storage to enhance operational flexibility and reliability. Two notable tools in this category are linepack and CNG.

Linepack is not a formal storage facility but an inherent feature of natural gas pipeline systems. Gas system operators, including local distribution companies (LDCs), can manage the amount of gas within transmission and distribution pipelines by adjusting pressure levels. This ability to “pack” additional natural gas molecules into the system serves as a short-term buffer against hourly fluctuations in supply and demand. Linepack helps enable system operators to respond to rapid intraday changes in demand, even in instances when upstream supply may be temporarily insufficient.[27]

CNG is another form of storage, produced by compressing natural gas to less than 1 percent of its volume at standard atmospheric pressure.[28] CNG offers a flexible, transportable form of natural gas storage that complements underground and LNG systems, particularly in areas without pipeline access or geological suitability for large-scale storage. CNG is stored in high-pressure cylinders and delivered via truck-based transport systems—referred to as virtual or mobile pipelines—to end-users such as utilities, industrial sites, or remote facilities.[29] These mobile storage options help meet local demand during peak events, outages, or infrastructure constraints and are commonly used in regions where underground or LNG storage is unavailable or limited.

CNG storage systems use various cylinder types that vary in pressure tolerance, weight, and capacity. Each type’s composition and design make it suitable for specific applications, such as bulk transportation, stationary storage, or vehicular applications.[30] Though CNG storage volumes are relatively small compared to underground or LNG storage, their modularity and portability make them a strategic asset. When deployed

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[24] https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/Jurisdiction_49_CFR_Part_193.pdf
[25] https://www.exxonmobillng.com/-/media/project/wep/exxonmobil-lng/lng-us/pdf/110-fsru.pdf
[26] https://www.econnectenergy.com/articles/how-does-regasification-of-lng-work
[27] American Gas Foundation. (2021). *Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience.* https://gasfoundation.org/wp-content/uploads/2021/01/Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf
[28] https://afdc.energy.gov/fuels/natural-gas-basics
[29] https://astforgetech.com/compressed-natural-gas-cng-storage-options-ultimate-guide/
[30] *Id.*

effectively, CNG enhances local system flexibility, supports peak-shaving operations, and contributes to overall reliability.

3. Market Landscape and Participants

Natural gas storage is a critical component of the effective operation of the natural gas system. For example, natural gas utilities and pipelines rely on access to natural gas storage for reliability during the winter heating season. Other market participants, including natural gas producers and marketers, rely on storage to balance production flows, particularly during the warmer months of the year, and deliver gas into the market at economically advantageous times.

This section will discuss the primary users of natural gas storage and the state and federal government regulators who oversee and promulgate regulations related to safety, operational issues, and market participation of storage facilities.

Physical and Operational Characteristics

Natural gas storage facilities are owned and operated by interstate pipeline companies, LDCs, LNG peak shaving operators, and independent operators. Natural gas stored in facilities owned by independent storage operators is often held under lease for shippers, marketers, and LDCs.

According to data from the EIA's 191 Field Level Storage Report for underground storage assets in 2023,[31] 53 percent of U.S. working gas capacity is owned and operated by interstate and intrastate pipeline companies, 22 percent by local distribution companies, and 25 percent by independent storage operators.[32] As shown in Table 3, pipeline companies own 43 percent of the total deliverability, while LDCs own 24 percent and independent companies own 33 percent. However, independently owned storage facilities have higher daily deliverability rates on average than those owned by pipeline or utility companies. Notably, the average deliverability rate for independently owned storage facilities is 0.41 Bcf per day, while LDC-owned facilities average 0.22 Bcf per day. Pipeline company facilities average 0.27 Bcf per day.

Differences in capacity and deliverability reflect the unique physical configurations and economic roles of each facility type. These differences influence how they are designed, operated, and optimized for specific market functions such as seasonal balancing, peak demand response, or short-term arbitrage.

[31] Data for 2023 was updated in December 2024.
[32] Data represents all reported storage assets, including active and inactive fields.

Table 3

U.S. Underground Storage Capacity by Owner Type

Billion Cubic Feet (Bcf)

	Working Gas Capacity (Bcf)	% of Total	Maximum Daily Delivery (Bcf/d)	% of Total
Pipeline	2,534	53%	50	43%
LDC	1,058	22%	29	24%
Independent	1,207	25%	39	33%
Total	**4,799**	**100%**	**117**	**100%**

Table: American Gas Association • Source: Energy Information Administration • Created with Datawrapper

Regulated storage (*i.e.,* utility-owned facilities) helps utilities to meet customer demand needs, while merchant storage (*i.e.,* pipeline and independently owned facilities) contract capacity to third-party shippers.[33] While some pipeline-owned storage is reserved for operational needs such as load balancing and system support, the majority is leased to other industry participants under merchant arrangements.[34] ICF International identifies these third-party shippers using FERC's Index of Customer data released by all interstate pipelines and certain independent storage operators in the first quarter of 2025. As illustrated in Figure 2, 60 percent of storage capacity is contracted by utilities, 27 percent by marketers, and 9 percent by pipelines.[35]

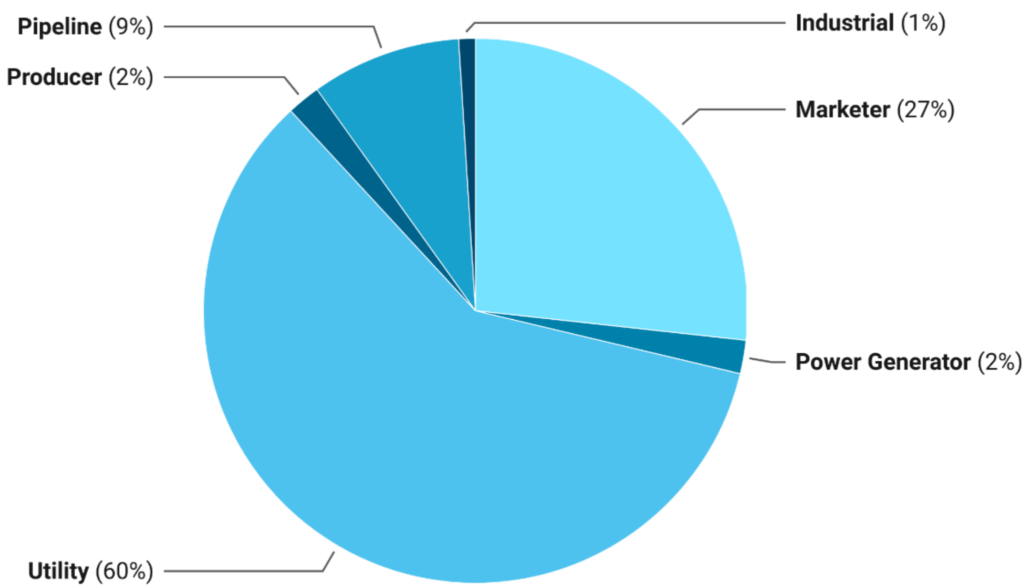
[33] Fang, H., Ciatto, A., & Brock, F. (2016). *U.S. Natural Gas Storage Capacity and Utilization Outlook.* https://www.energy.gov/sites/prod/files/2017/01/f34/U.S.%20Natural%20Gas%20Storage%20Capacity%20and%20Utilization%20Outlook_0.pdf

[34] https://www.eia.gov/naturalgas/storage/basics/

[35] Note: Analysis reflects data from the EIA's 191 Field Level report as of December 2014. The share of storage capacity contracted by shipper industry will vary based on more recent data.

Figure 2

Contracted Underground Storage Capacity by Shipper Industry, Q1 2025



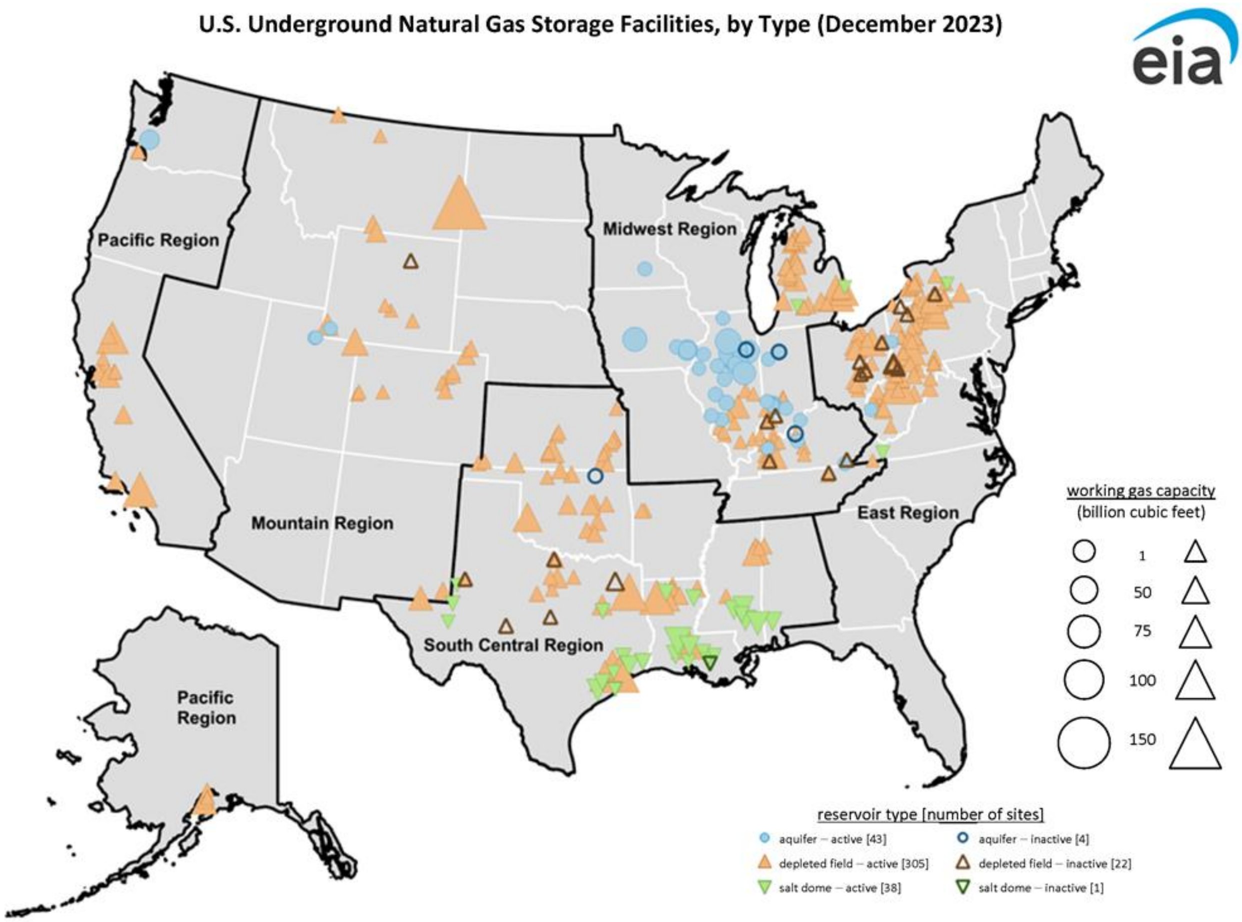
Percentages may not foot due to rounding.

Chart: American Gas Association • Source: Hitachi Energy Velocity Suite, ICF International • Created with Datawrapper

As of December 2024, the EIA reported data for 413 underground storage facilities across the U.S. Of these facilities, 393 are active fields with a combined working gas capacity of 4,772 Bcf, spanning 31 states. The majority (79 percent) of these storage facilities are depleted reservoirs, while 11 percent are aquifers. The remaining 10 percent are salt domes. A map of active and inactive facilities located in the continental U.S. is provided in Figure 3.[36]

[36] Note: As of this report's release, the EIA has not published an updated map reflecting their December 2024 update. Figure 3 reflects 2022 data released in December 2023.

Figure 3



Source: Energy Information Administration

Regionally, active underground storage assets are most concentrated in the South Central, Midwest, and East, accounting for more than 80 percent of the total working gas capacity. Figure 4 provides an overview of regional storage characteristics.

Figure 4

U.S. Regional Underground Storage Characteristics

Active Fields, Percent of Total

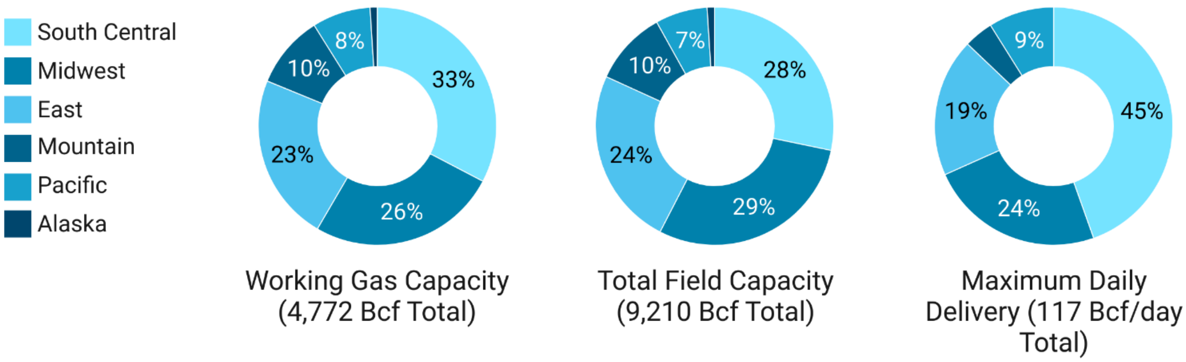
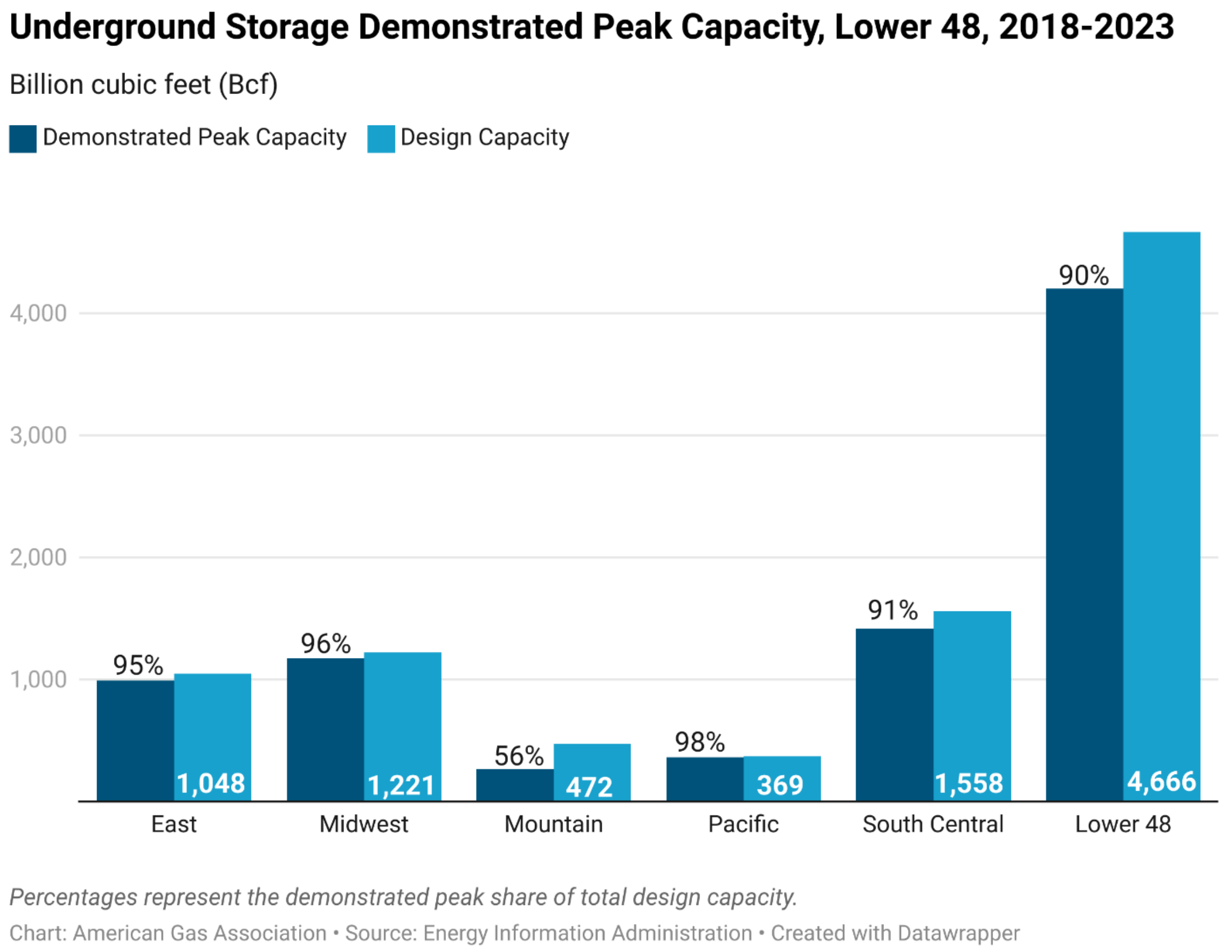


Chart: American Gas Association, Subject to Revision • Source: U.S. Energy Information Administration, 191 Field Level Storage Data • Created with Datawrapper

As of November 2023, the demonstrated peak capacity of underground storage in the lower 48 was 90 percent. The data depicted in Figure 5 represents December 2018 through November 2023. In all regions except the Mountain, the demonstrated capacity exceeds 90 percent, reaching as high as 98 percent in the Pacific region. Determining storage asset utilization is based on the demonstrated peak capacity rather than the design capacity, as it is a more realistic measure of the capabilities of active storage fields.

Figure 5

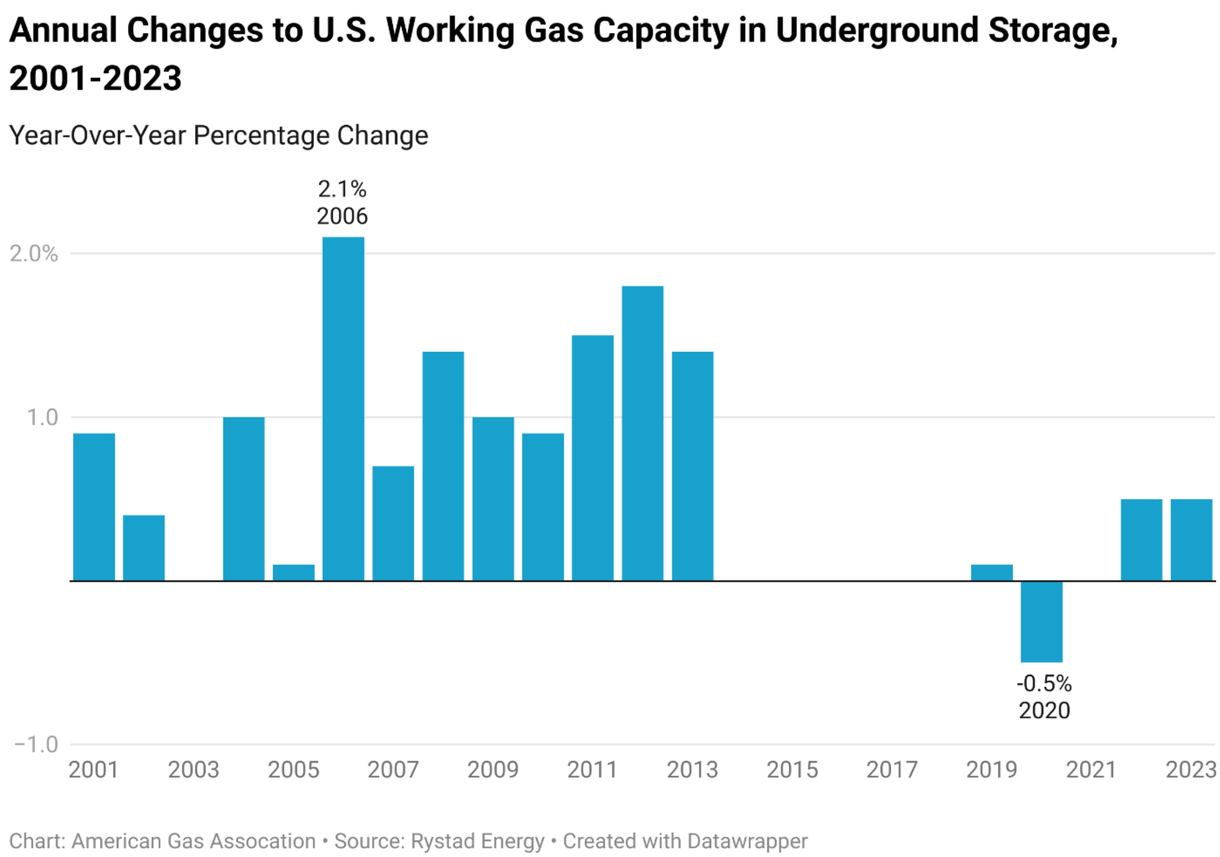


In recent years, capacity additions to underground storage have slowed significantly. Between 2001 and 2013, additions to working gas capacity grew steadily at an average rate of 1 percent per year. Between 2014 and 2023, the average annual growth rate slowed to 0.1 percent. In 2020, working gas capacity declined by 23.6 Bcf year-over-year, primarily driven by a 23 Bcf reduction in West Virginia after the Majorsville DP facility was taken offline until 2023.[37]

[37] Notably, the EIA's reported peak demonstrated capacity also declined in 2020 by a total of 8 Bcf year-over year. A 34 Bcf reduction in the Pacific region was the primary reason for this decline. It reflects the exclusion of pre-2015 peak levels at Aliso Canyon from the five-year average, following the facility's operational restrictions after 2015. *See* https://www.eia.gov/todayinenergy/detail.php?id=48216

Figure 6 illustrates the year-over-year trends of working gas capacity in underground storage from 2001 to 2023.

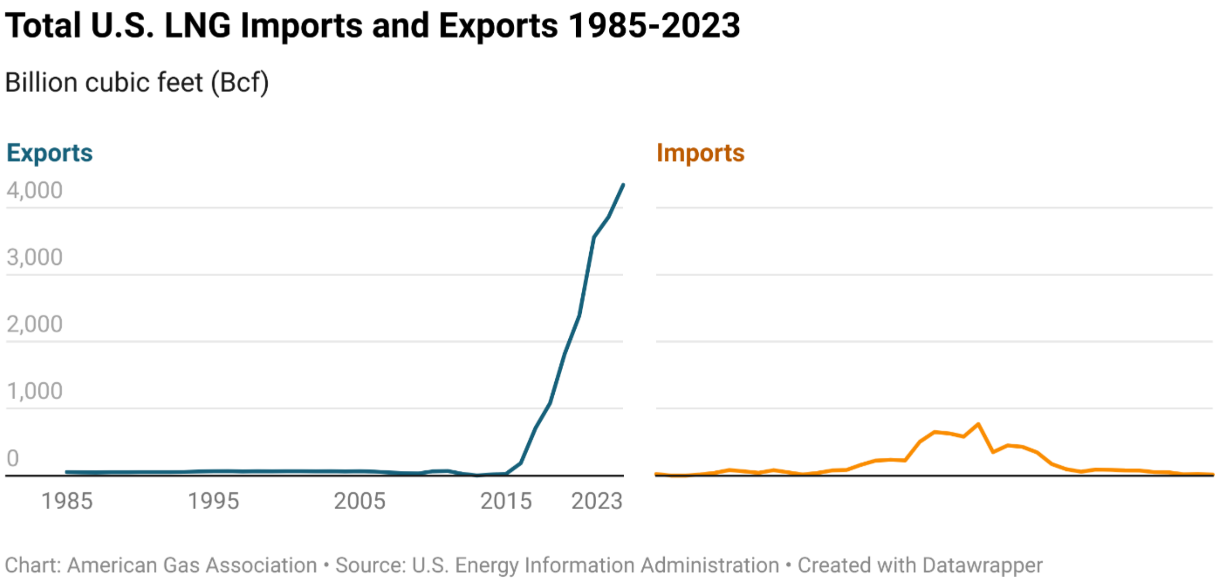
Figure 6



LNG storage capacity in service has grown over the last several years as U.S. LNG export capacity has expanded, driven by the so-called shale revolution,[38] since major export facilities have on-site LNG storage. As of 2023, U.S. LNG export volumes reached 11.2 Bcf per day, a seven-fold increase since 2013. This reflects the evolution of the U.S. from once a net importer of natural gas to now the world's leading exporter.[13] Figure 7 illustrates this shift.

[38] The shale revolution refers to the rapid growth in U.S. oil and natural gas production in the mid-2000s when new drilling techniques unlocked vast reserves of oil and natural gas from deep underground shale rock. As a result, the U.S. became the world's largest natural gas producer and significantly boosted domestic energy security. The shale boom reshaped global energy markets, lowered energy prices, and boosted energy independence.

Figure 7



According to PHMSA, as of 2023, there are 182 total LNG storage facilities with a combined service capacity of 68.3 Bcf.[39] The majority of LNG storage facilities (*i.e.*, 96.7 percent) were in service as of 2023, offering more than 68.2 Bcf of capacity. Approximately 84.6 percent were classified as intrastate facilities, and more than half sourced LNG by truck. Most of the facilities were logged as peak shaving facilities (41.8 percent), followed by mobile/temporary facilities (22 percent), baseload (15.4 percent), and satellite (14.3 percent). The remaining facilities were logged as "other" for purposes such as storage with liquefaction, merchant, transportation, and peak shaving without fixed storage.[40] Many of these facility types are described in Table 2. Figure 8 illustrates facility location by facility status for all U.S. states. Three in-service facilities in Puerto Rico are not reflected on the map, and 12 additional facilities did not have an associated zip code. Eleven of those were logged as in service, and one was logged as abandoned.

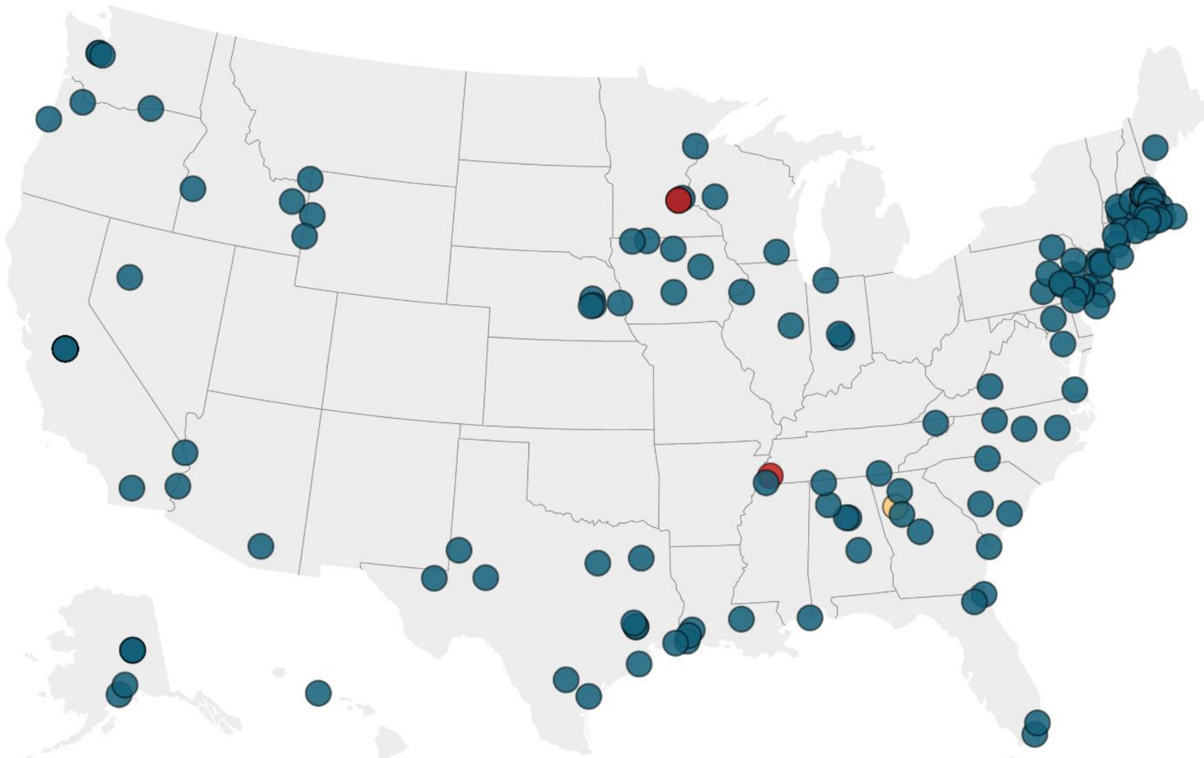
[39] https://www.phmsa.dot.gov/data-and-statistics/pipeline/liquefied-natural-gas-lng-facilities-and-total-storage-capacities
[40] Note: This dataset does not include storage located at LNG export facilities.

Figure 8

LNG Storage Facilities by Status 2023

Facility Status

Abandoned In Service Retired



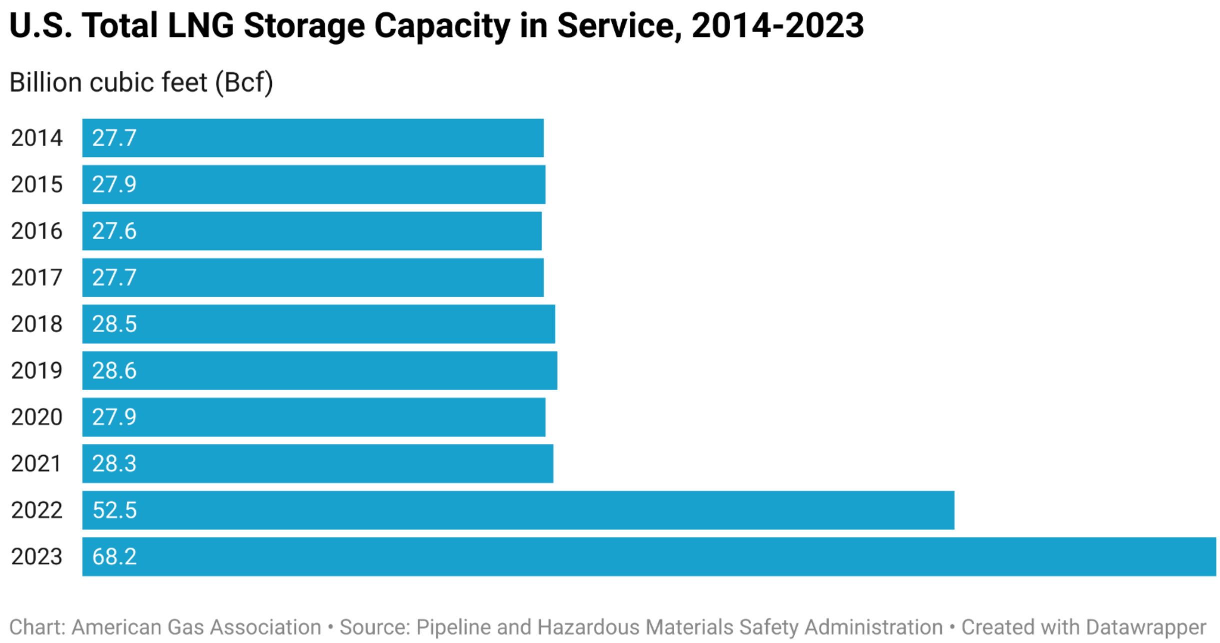
Three in service facilities located in Puerto Rico are not reflected here.

Map: American Gas Association • Source: Pipeline and Hazardous Materials Safety Administration • Created with Datawrapper

Net additions to LNG storage also increased significantly between 2021 and 2023, raising the total capacity in service from 28.3 Bcf in 2021 to 68.2 Bcf in 2023, a 141.5 percent increase, according to PHMSA data. Over the same period, the total number of in-service LNG storage facilities increased by seven to 176. From 2014 to 2020, annual changes in LNG capacity in service were relatively low, averaging just 0.1 percent per year. Figure 9 shows the total LNG storage capacity in service and the annual percentage change in capacity between 2014 and 2023, as reported by PHMSA.[41]

[41] Note: PHMSA provides annual data reported by LNG operators as required by 49 CFR Parts 191 and 195. Available data for 2010 through 2023 indicate rising capacity to 347.9 Bcf in 2012, then steep drops to 75.5 Bcf in 2013 and 27.7 Bcf in 2014. Absent additional clarity as to why these trends occurred, AGA is not citing data before 2014 at this time. For more information, see https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

Figure 9



Jurisdictional Considerations

Natural gas storage is regulated by a combination of federal agencies and state jurisdictions, depending on whether the storage facilities and related infrastructure operate in an interstate or intrastate capacity. At the federal level, the Federal Energy Regulatory Commission (FERC) regulates the construction and operation of interstate natural gas storage facilities, while PHMSA oversees the safety of underground storage facilities.

Following market evolutions brought about by the Natural Gas Policy Act of 1978, FERC issued Order 636 in 1992, which restructured the natural gas industry and, in part, required interstate pipeline companies to unbundle their sales and transportation services.[42] As a result, FERC enhanced competition by requiring open access to transmission networks to third parties, allowing for improved market efficiency while maintaining regulatory oversight of the rates charged for transporting natural gas.

Further, the Energy Policy Act of 2005 revised the Natural Gas Act and gave FERC authority to grant market-based rates for new storage capacity.[43] Specifically, FERC may authorize natural gas companies to provide storage and storage-related services at market-based rates for new storage capacity placed into service after August 2005, even if the company is unable to demonstrate it lacks market power. To make this authorization, FERC must determine that market-based rates are in the public interest and needed to encourage the construction of the capacity, and that customers are adequately protected.[44] FERC is required to ensure that reasonable terms and conditions are in place to protect consumers, and it must periodically review the market-

[42] https://www.ferc.gov/order-no-636-restructuring-pipeline-services
[43] Energy Policy Act of 2005, Pub. L. No. 109-58, section 312, 119 Stat. 594, 688 (2005) codified at 15 U.S.C. § 717c(f).
[44] https://www.ferc.gov/industries-data/natural-gas/natural-gas-storage

based rates authorized to ensure said rates remain just, reasonable, and not unduly discriminatory or preferential.

More recently, PHMSA revised its rules and procedures for the oversight of natural gas storage facilities following the Aliso Canyon incident in 2015. The final rule was published in 2020 and required mandatory compliance with recommended practices regarding the design, operation, and maintenance of underground storage facilities.[45] Further, the rule enhanced recordkeeping and reporting requirements for operators and instituted integrity management practices such as regular assessments and risk management protocols for underground facilities.

At the state level, regulatory oversight for natural gas storage typically falls under the purview of Public Utility Commissions (PUCs) or other state advisory agencies. State-level regulation focuses on intrastate facilities only and could include such components as siting and construction of new storage facilities, cost recovery, and safety oversight. For example, in 2023, the California Public Utilities Commission increased natural gas inventory levels at the Aliso Canyon Natural Gas Storage Facility in an effort to guard against price spikes.[46] In Texas, the Alternative Fuels Safety Department of the Railroad Commission (RRC) has oversight on natural gas storage and distribution of alternative fuels, including both LNG and CNG, conducts safety evaluations of facilities and equipment, and provides licensing and training for those working in the industry.[47] A separate agency, the Texas Commission on Environmental Quality, is responsible for overseeing emissions control from storage tanks and coordinates with the RRC.[48]

In the "Safety of Underground Natural Gas Storage Facilities" (85 FR 8104) rule issued in 2020, PHMSA clarified the roles and responsibilities of state regulatory agencies for underground storage facilities. As part of the rule, PHMSA reinforced that no existing state roles have been altered and that states can enforce more stringent safety standards for intrastate underground storage facilities so long as those standards comply with federal regulations. States also retained the authority for siting and permitting for intrastate facilities and environmental protections for surrounding areas.

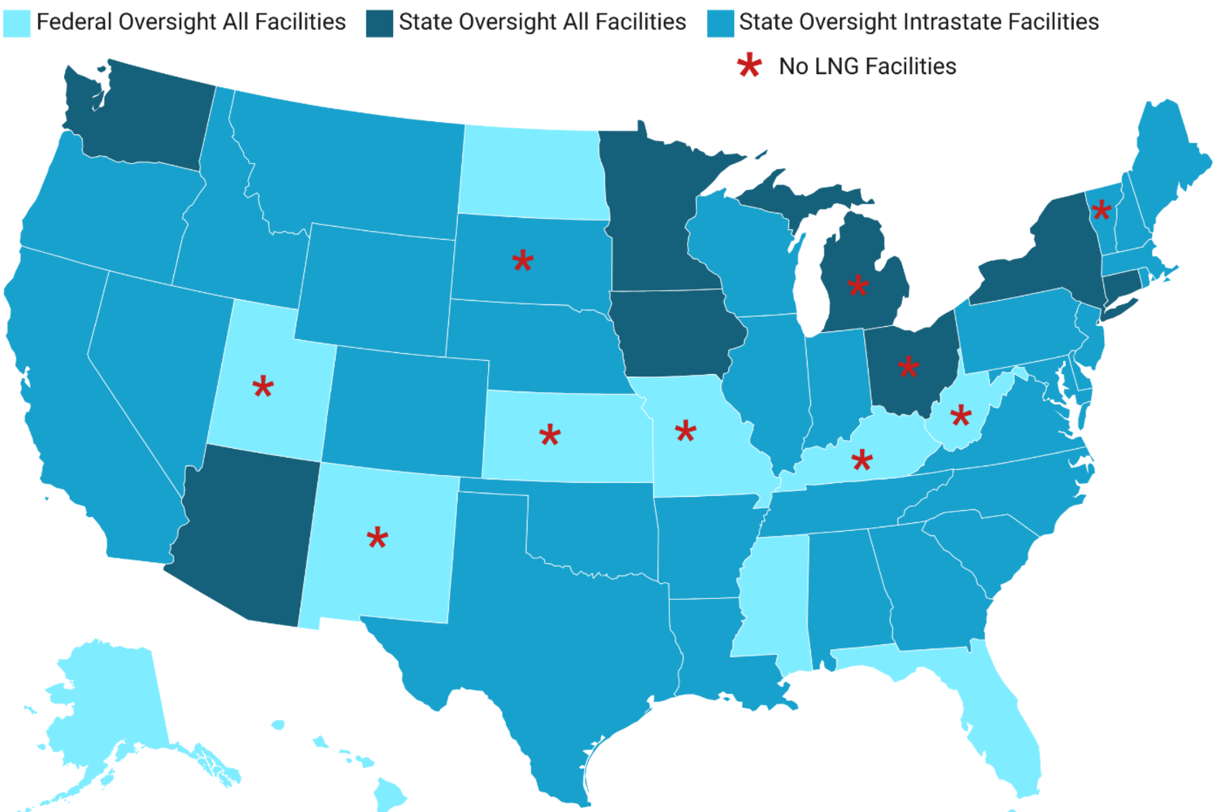
Similarly, LNG storage facilities are overseen by regulatory bodies such as FERC, PHMSA, state-level agencies, and the U.S. Coast Guard (USCG). Depending on the location and use of an LNG facility, it may be regulated by several federal and state regulatory agencies at the same time.[49] The Natural Gas Pipeline Safety Act of 1968, which authorizes PHMSA to regulate the pipeline transportation of natural gas and other gases, includes the transportation and storage of LNG.[50] PHMSA "has the exclusive authority to establish and enforce safety regulations for onshore LNG facilities."[51] These regulations are contained in the Code of Federal

[45] Safety of Underground Natural Gas Storage Facilities. 85 FR 8104. https://www.federalregister.gov/documents/2020/02/12/2020-00565/pipeline-safety-safety-of-underground-natural-gas-storage-facilities
[46] https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-takes-action-to-enhance-energy-affordability-for-ratepayers-in-southern-california-2023
[47] https://rrc.texas.gov/about-us/organization-and-activities/rrc-divisions/oversight-safety-division/
[48] https://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/tanks/nsrauth_tanks.html
[49] https://www.ferc.gov/natural-gas/lng
[50] https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/jurisdiction-lng-plants
[51] https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-regulatory-documents

Regulations (CFR) at Title 49 Part 193 and apply to LNG facilities that receive or deliver gas to a pipeline regulated under 49 CFR 192. State agencies often work in partnership with PHMSA to ensure that both federal and state requirements are met. The map in Figure 10 depicts the various regulatory authorities over intrastate and interstate facilities.[52]

Figure 10

U.S. Regulatory Authority Over Intrastate & Interstate LNG Facilites



Hawaii updated to reflect in-service facility as of 2018. D.C. is federally regulated but has no LNG facilities.

Map: American Gas Association • Source: Pipeline and Hazardous Materials Safety Administration (PHMSA) • Created with Datawrapper

Like PHMSA, FERC is responsible for inspecting peak-shaving, LNG satellite facilities, and vehicular fuel LNG plants connected to the interstate gas transmission system.[53] PHMSA is responsible for the standards that govern the location and design of interstate LNG facilities, while FERC is responsible for determining whether the proposed facilities meet public interest requirements. The agencies have established a Memorandum of Understanding (MOU) outlining the coordination framework.[54] LNG projects are approved and built under

[52] https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/jurisdiction-lng-plants
[53] https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-regulatory-documents
[54] https://www.ferc.gov/news-events/news/ferc-phmsa-sign-mou-coordinate-lng-reviews

FERC's oversight as long as the facility is in operation.[55] Moreover, under Section 3 of the Natural Gas Act, FERC authorizes the siting and construction of near-shore LNG import or export facilities. Additionally, companies that want to import LNG into or export it from the U.S. must be authorized to do so by the Department of Energy (DOE).[56]

The USCG, in coordination with the Maritime Administration (MARAD), oversees the safety, security, and environmental regulation of LNG deepwater ports and marine transfer areas at waterfront facilities.[57] The USCG conducts waterway suitability assessments, manages the deepwater port licensing process, and develops regulatory guidance for design, construction, and operation phases. These responsibilities are governed by federal laws, including the Maritime Transportation Security Act and the Deepwater Port Act.[58]

Market Interactions

U.S. underground, LNG, and CNG storage are essential for balancing supply and demand, providing service to consumers, and mitigating market risk. Therefore, storage assets are inherently valuable as operational resources and help to reduce consumer exposure to price volatility.

In the domestic market, underground storage inventories serve as a key indicator of relative natural gas supply and demand trends, and changes to underground storage may trigger a commensurate price response in the market.[59] Comparing current storage levels to historical averages can help identify if the market is experiencing deficits or surpluses relative to typical storage levels, where current inventories are often measured against a rolling five-year average or other historical metrics. Working gas inventory deficits or surpluses relative to historical levels can result from demand patterns due to weather or other macroeconomic factors, shifts in flowing gas supplies due to changes in natural gas production or infrastructure maintenance, and other market events.

For example, a severe winter heating season may produce higher-than-average withdrawals on storage inventories, leaving lower-than-average inventories in storage. Similarly, a warmer-than-normal winter can have the opposite effect. The 2023-2024 winter was the warmest on record for the U.S., with an average temperature of 37.6° Fahrenheit, 5.4 degrees above average, and resulted in a surplus of storage inventories of 262 Bcf above the five-year maximum for the week ending March 29, 2024.[60] The interaction between storage and demand seasonality is discussed further in Section 4.

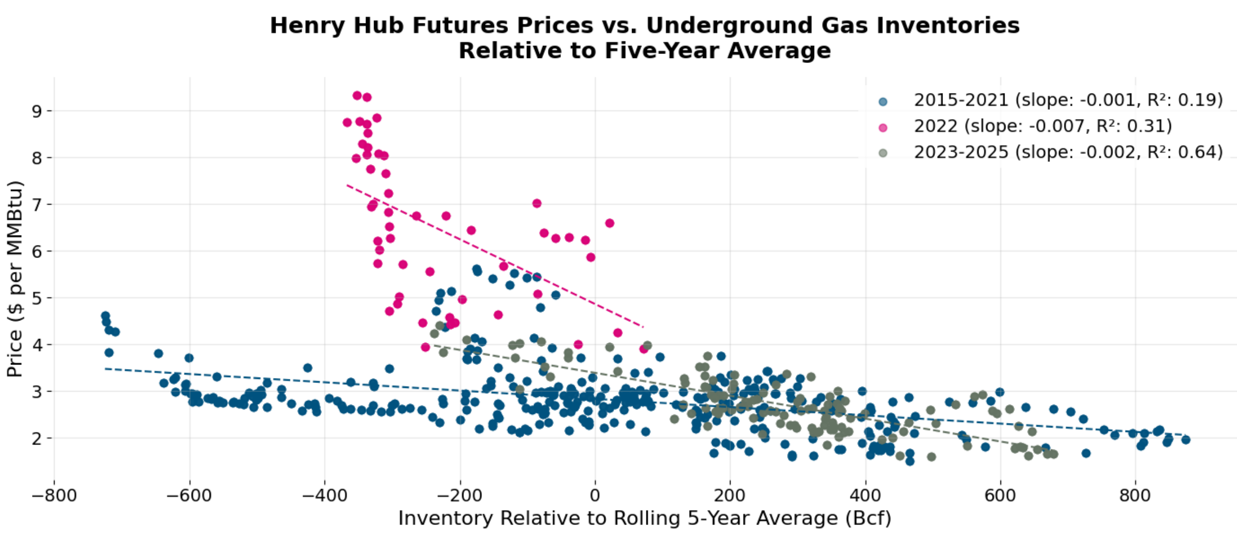
The amount of gas in storage also influences natural gas prices because fluctuating inventory levels can prompt traders to adjust their purchasing strategies and shape expectations for future supply availability. Additionally, when storage inventories are low, spot prices may be more responsive to the impact of structural

[55] https://www.ferc.gov/natural-gas/lng
[56] https://www.energy.gov/fecm/articles/does-role-lng-sector
[57] https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-regulatory-documents
[58] *See also* 33 CFR Parts 127.
[59] Rubaszek, M., & Uddin, G. S. (2020). The Role of Underground Storage in the Dynamics of the US Natural Gas Market: A Threshold Model Analysis. *Energy Economics, 87*, 104713. https://doi.org/10.1016/j.eneco.2020.104713
[60] https://www.noaa.gov/news/us-had-its-warmest-winter-on-record

shocks, such as weather disasters, economic shifts, or supply disruptions.[61] In 2024, Henry Hub spot prices hit historic lows during a period of higher-than-average storage inventories following the 2023-2024 winter heating season. In real terms, prices averaged $1.51 per MMBtu in March 2024, the lowest monthly price on record. Spot prices also reached the lowest annual average of $2.21 per MMBtu in 2024.[62]

Figure 11 plots Henry Hub futures prices against underground storage inventories relative to the rolling five-year average. Simple trend lines have been included for select periods before and after 2020. Three distinct trends emerge. Between 2015 and 2020, prompt-month natural gas futures prices appear modestly responsive to changes in storage inventory levels, with prices rising moderately as inventories show increasing deficits relative to the five-year average. During 2022, prompt-month natural gas futures prices were much more responsive to changes in inventory levels. This trend is largely driven by natural gas price increases that began in the spring of 2022 and extended through the summer before moderating by the end of 2022. The third trend from 2023 to 2025 is more in line with pre-2022 patterns. It's important to note that global commodities all saw a run-up in pricing during this period in 2022, so the relative contribution of North American market fundamentals versus other market factors contributing to the higher natural gas prices during 2022 is not clear. Therefore, predictions about where the market may be headed in the future cannot be inferred from this chart.

Figure 11



LNG storage is far smaller than underground working-gas inventories, yet it can also influence domestic market pricing and supply availability. Peak shaving facilities are critical for meeting peak day demand requirements and maintaining gas distribution system pressures during periods of high demand or supply constraints. As mentioned in Section 2, peak shaving facilities are designed to supplement short-term supply, with inventories often utilized over just a few days, followed by a gradual refill taking place over several months. This process

[61] Rubaszek, M., & Uddin, G. S. (2020). The Role of Underground Storage in the Dynamics of the US Natural Gas Market: A Threshold Model Analysis. *Energy Economics, 87*, 104713. https://doi.org/10.1016/j.eneco.2020.104713

[62] Prices adjusted for inflation using U.S. Bureau of Labor Statistics December 2024 CPI-U.

can be extended if the market faces a prolonged period of heightened prices. Because peak shaving facilities sit behind the citygate, the price of gas at key hubs across the U.S. is less likely to be directly impacted by LNG storage inventory levels at peak shaving facilities operating behind the citygate.[63]

LNG export facilities offer a different kind of flexibility. Although they generally run at baseload to meet long-term contracts, they can curtail feedgas during periods of exceptionally high demand, particularly in winter months, redirecting gas into the market to serve domestic supply needs.[64] LNG export facilities can also vaporize stored LNG and send it into the market, depending on contractual and commercial conditions and arrangements.[65]

International markets also depend on LNG storage. Floating storage units (FSUs), as well as tanks at LNG import and export facilities, can contribute as buffers to smooth supply-demand imbalances. If global LNG markets face oversupply or weakened demand, gas tends to be stored at import and export facilities or on FSUs as the market adjusts to the demand shifts. In contrast, if global LNG markets experience supply shortages or heightened demand, LNG is often withdrawn from these facilities. In either case, the price of LNG in different regions converges toward the price of natural gas in the region those facilities serve. Additionally, at LNG import facilities, low storage can indicate increasing domestic demand or supply constraints and vice versa.

U.S. LNG feedgas is one component of domestic demand that helps shape domestic supply-demand fundamentals, which in turn shape domestic pricing. Even as LNG exports have grown significantly since 2016, according to industry research, there is little evidence that LNG feedgas for exports has had a sustained or significant direct impact on domestic prices to date.[66] Expectations are that U.S. LNG export demand will continue to rise, and with it, evolving dynamics regarding domestic and international markets. Importantly, as LNG export demand grows, additional domestic natural gas storage will likely be needed to support market flexibility.[67]

4. Seasonality, Reliability, and Resiliency

Paramount to the discussion of the value that storage provides to the domestic energy system are the seasonality, reliability, and resiliency that storage offers. Stored natural gas plays a crucial role during key seasonal shifts, such as heat waves and severe cold events, as well as hurricanes and wildfires. Natural gas

[63] The "citygate" is generally the point where natural gas is transferred from an interstate or intrastate pipeline to a local natural gas utility. *See* https://www.aga.org/research-policy/resource-library/natural-gas-prices/
[64] Feedgas is the amount of natural gas delivered via pipeline to liquefaction facilities to be converted to LNG.
[65] https://www.spglobal.com/commodity-insights/en/news-research/latest-news/lng/012224-us-lng-exporters-canceled-cargoes-amid-freeze-as-us-gas-prices-surged
[66] https://lngallies.com/wp-content/uploads/2024/02/USLNG-Study-2024-02-15.pdf
[67] https://www.spglobal.com/commodityinsights/ko/market-insights/latest-news/natural-gas/032824-us-gas-prices-to-be-increasingly-linked-to-international-markets-through-lng

service to homes and power generators is enhanced by the availability of underground and LNG storage, which serves to mitigate disruptions to the delivery system or to meet significant short-term demand requirements.

Storage is also critical for providing year-round system reliability and resiliency for natural gas customers and for other parts of the energy system. Reliability and resiliency are distinct concepts. Resilience is “the ability of the energy system to prevent, withstand, adapt, and recover from a system disruption.”[68] In contrast, reliability “focuses on the ability of the energy system to deliver services in the quantity and with the quality demanded by end-users.”[69] The key distinction between these two concepts is the event type. A reliable system responds adequately to high-probability, low-impact events and disruptions such as common storms. In contrast, a resilient system responds effectively to low-probability, high-impact events such as hurricanes.

Seasonal Role of Stored Natural Gas

In the U.S., natural gas consumption patterns are influenced by various structural and seasonal factors, including temperatures. Natural gas consumption typically peaks during the winter months due to the significant demand for residential and commercial heating. However, natural gas consumed by the electric power sector for electricity generation tends to peak in the summer months when warmer temperatures drive consumer demand for more electricity for air conditioning.[70]

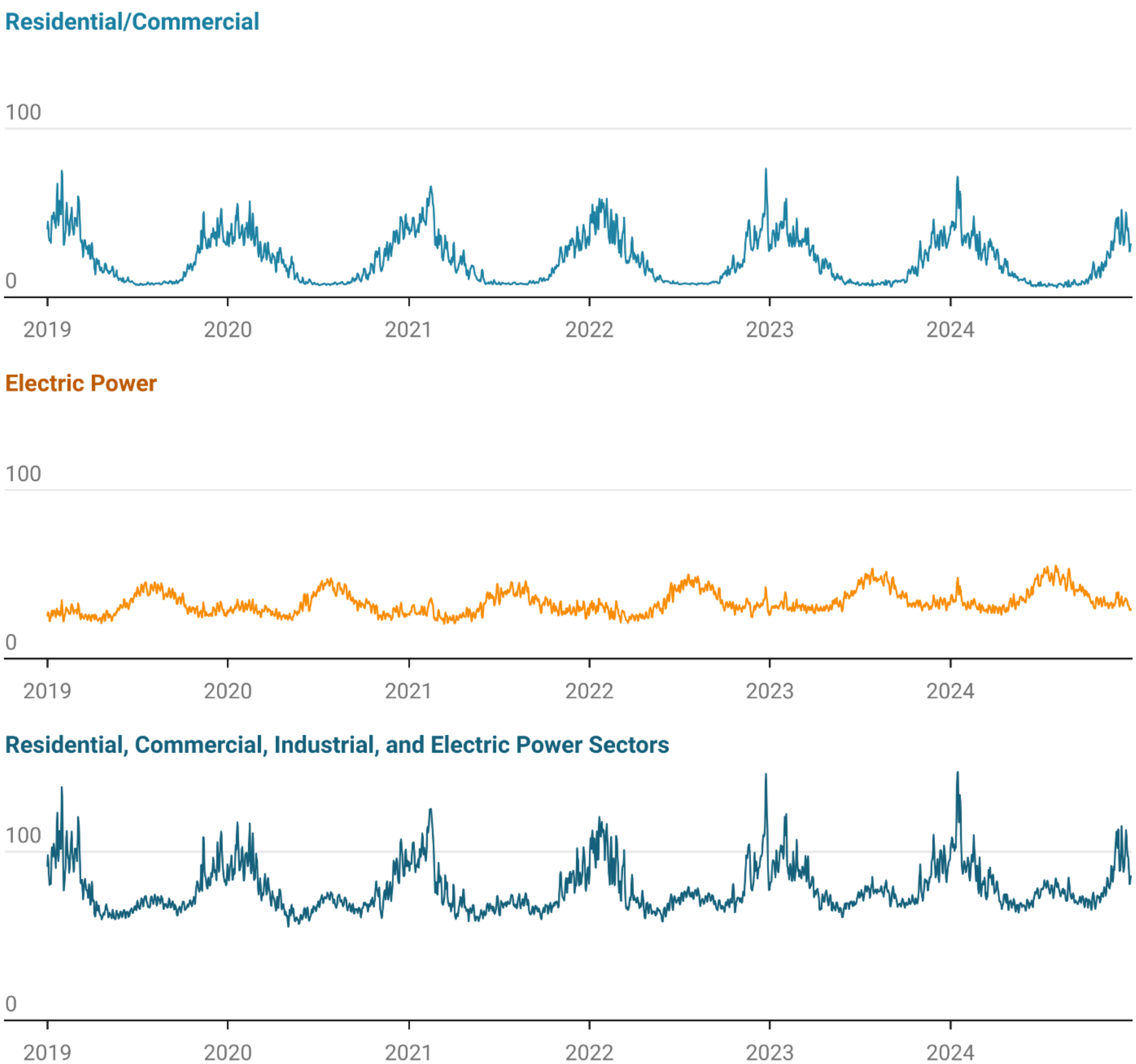
Figure 12 depicts daily residential/commercial and electric power sector demand from 2019 through 2024. As the chart shows, residential/commercial demand peaked on December 24, 2022, for this period. Comparatively, the electric power sector reached an all-time daily consumption record on August 1, 2024.

[68] American Gas Foundation. (2022). *Enhancing and Maintaining Energy System Resilience: Areas of Focus and Change*. https://gasfoundation.org/wp-content/uploads/2022/10/AGF-Enhancing-and-Maintaining-Gas-and-Energy-System-Resiliency-Report-NOV.pdf
[69] *Id*.
[70] Natural gas demand in the Industrial sector follows a similar pattern to the Residential and Commercial sector in that demand tends to peak during the winter and trough during the summer. However, the range of demand peaks and troughs is much narrower with Industrial sector consumption.

Figure 12

Daily Natural Gas Consumption for Select Sectors 2019 – 2024

Billion cubic feet per day (Bcf/d)



Subject to revision

Chart: American Gas Association • Source: S&P Global Commodity Insights © 2025 by S&P Global, Inc. • Created with Datawrapper

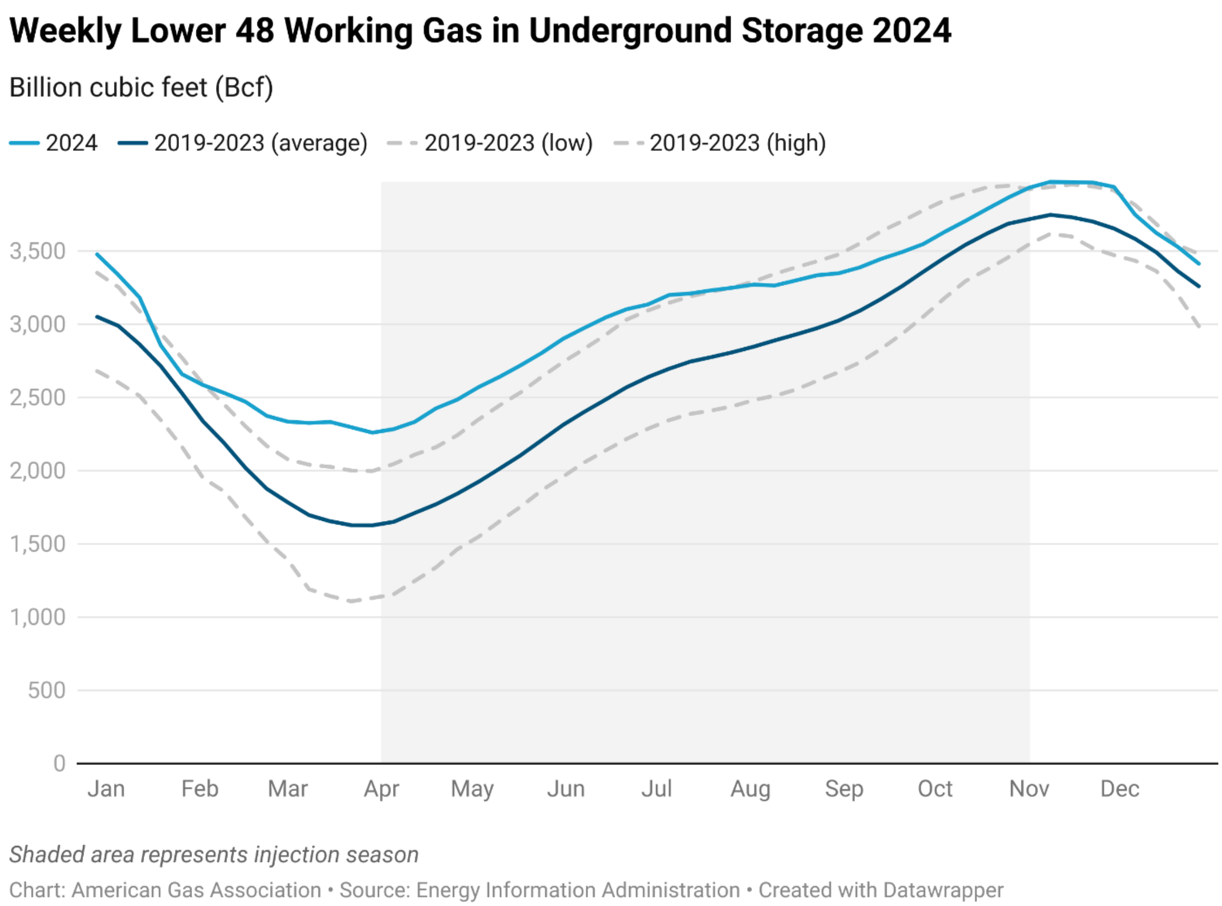
The U.S. generally injects excess natural gas produced during the warmer months (*i.e.*, injection season, which runs from April 1 to October 31 of each year) and generally withdraws stored natural gas as needed during the colder months (*i.e.*, withdrawal season, which runs from November 1 to March 31 of each year). Various factors, such as changes in demand or production, can impact storage levels during each of these seasons. As demand increases, such as during the winter months or heat waves in the summer, stored natural gas becomes essential to maintain resilience and reliability.

During the summer months, the pace of injections may slow as summer cooling demand redirects volumes toward end uses such as electric power generation. In fact, in some regions, the demand during peak summer months can be so large that it necessitates net withdrawals from storage during the injection season.[71] Similarly, if production lags annual trends due to weather-related events (*e.g.*, hurricanes impacting production and transmission hubs) or market pressures (*e.g.*, falling natural gas prices leading to producer curtailments), injection volumes into underground storage tend to slow.

Figure 13 depicts the changes in working gas in underground storage for the lower 48 throughout 2024. The graph shows increasing working gas storage volumes during the injection season and declining underground inventories during the withdrawal season. According to the EIA, weekly storage levels were 3,476 Bcf as of December 29, 2023, and 3,336 Bcf as of January 5, 2024. For the week ending December 27, 2024, total underground inventory was 3,413 Bcf, 154 Bcf higher than the five-year average from 2019 to 2023. In 2024, weekly underground storage levels exceeded both the five-year average and the upper end of the five-year range in approximately 60 percent of the weeks.

[71] Assuming production levels are not increasing in tandem.

Figure 13



Annual LNG storage volume addition and withdrawal data indicate significant variability year-to-year, although the data is not available at the same weekly detail as underground storage inventories.[72] Over the last two decades, the EIA reports average net LNG additions of 4.4 Bcf per year for 12 of those years, while the remaining eight years represent net LNG withdrawals of 2.2 Bcf per year. Overall, net LNG additions for the U.S. averaged 1.8 Bcf per year for the most recent 20-year period.

LNG storage facilities are particularly critical for meeting peak winter demand, especially in regions with pipeline capacity constraints and limited access to underground storage facilities. For example, due to geological unsuitability, New England has no underground storage facilities, so it relies on LNG for 28 percent of its design day[73] supply in the winter.[74] LNG storage facilities are also commonly used for peak shaving

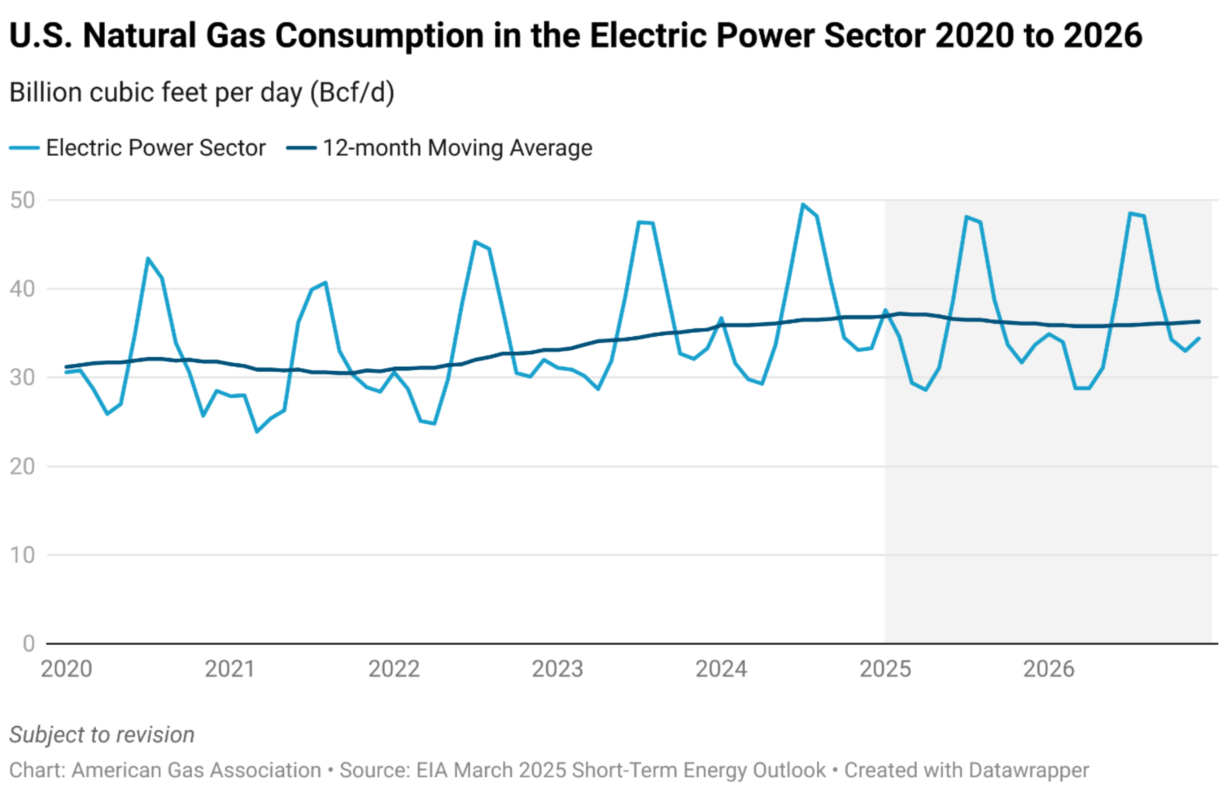
[72] In the context of LNG storage, storage additions are similar to underground storage injections in that LNG is being placed into storage.
[73] Design day refers to the coldest hypothetical winter day when demand is expected to reach its highest peak. Natural gas utilities use the design day as a tool for system planning and winter heating season preparation.
[74] https://northeastgas.org/about-lng

electricity demand during the summer. As such, unlike refill and withdrawal seasons for underground storage, there is not a general withdrawal and refill cycle for LNG.

Changing Landscape of Electric Generation

Over the last two decades, natural gas consumption by end-use sector has evolved in response to changing domestic needs.[75] According to the EIA, the industrial sector was the leading end-use consumer of natural gas in 2001, accounting for approximately 36 percent of total end-use consumption.[76] By 2024, that number had declined to about 29 percent. In contrast, demand in the electric power sector nearly doubled over the same period, increasing its share of domestic demand from 26.1 percent in 2001 to 45.3 percent in 2024.[77] Figure 14 shows the monthly trend of natural gas consumed by the electric power sector between January 2020 and December 2024, and projected demand through the end of 2026.

Figure 14

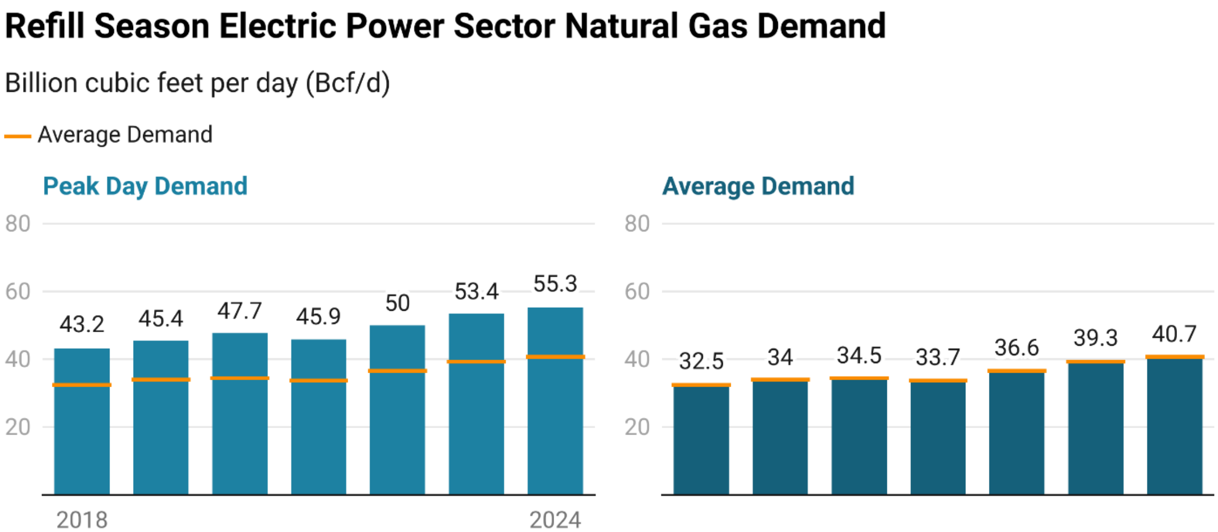


Both average and peak natural gas use in the electric power sector have increased. In the 2018 refill season, peak day demand for natural gas in the electric power sector was 43.2 Bcf per day. By the 2024 refill season, peak day demand had increased more than 28 percent to 55.3 Bcf per day. Similarly, the average demand for

[75] In this context, end-use refers to natural gas consumption by the residential, commercial, industrial, and electric power sectors only.
[76] https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm
[77] Over the same period, total natural gas consumption in the power sector increased by approximately 7.6 trillion cubic feet (Tcf) or 142 percent. For 2024 year-to-date through October, total natural gas consumed by the power sector was 11.5 Tcf.

natural gas during this time grew from 32.5 Bcf per day to 40.7 Bcf per day, an increase of just over 25 percent. From the 2018 to 2024 refill seasons, peak day demand has been 1.4 times larger than average demand. Figure 15 illustrates this trend. Comparatively, peak day and average demand during what are generally the two hottest months of the year—July and August—are nearly on par, with peak day demand being 1.1 times larger than average demand for each of these years.

Figure 15



Date ranges reflect April 1 through September 30 of each year.

Chart: American Gas Association • Source: S&P Global Commodity Insights © 2025 by S&P Global, Inc. • Created with Datawrapper

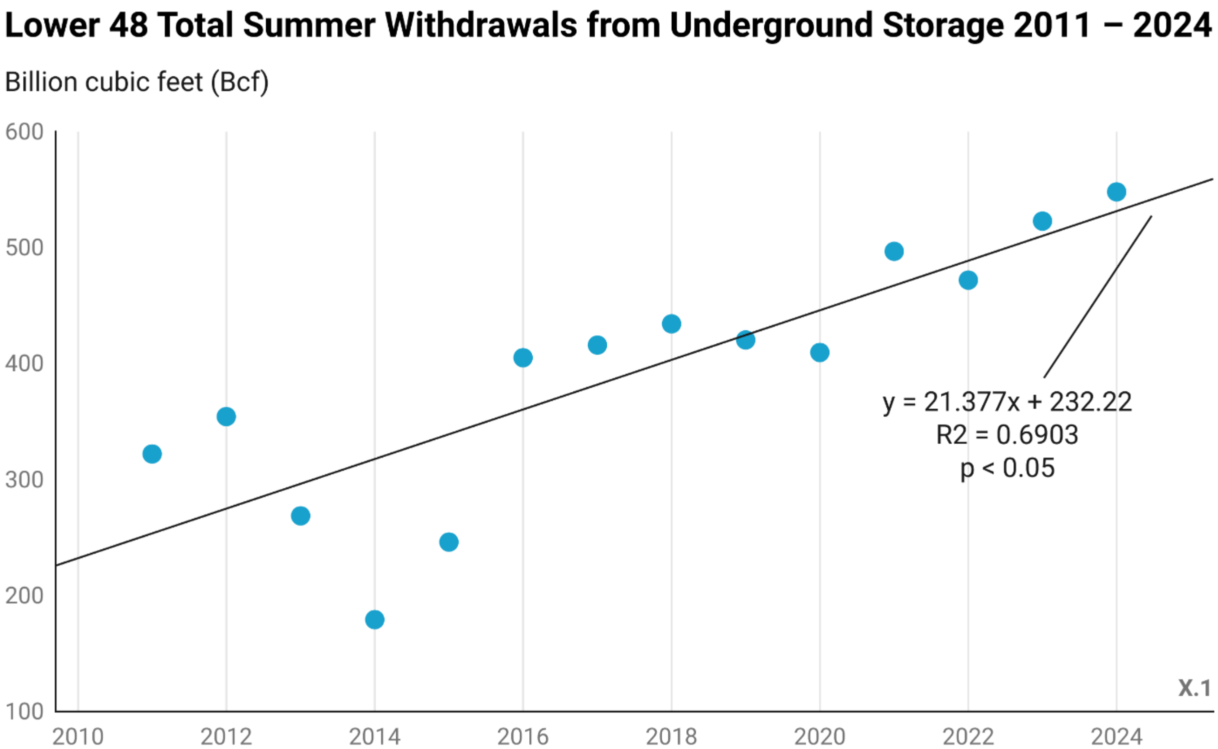
Coal plant retirements, low natural gas prices, low wind and hydropower output, and high cooling demand in some regions have also increased the demand for natural gas in the power sector.[78] The increased use of natural gas for electric generation has shifted the seasonality of demand and reduced seasonal price spreads. This fundamentally erodes the valuation of underground storage and impacts its use during the refill season. Section 5 will discuss the valuation of underground and LNG storage facilities, including seasonal price spreads, in further detail by considering both market-based and regulatory values.

During the summer months, total underground storage withdrawals have trended upward since 2011.[79] In the summer of 2024, withdrawals reached an all-time high of 548 Bcf. Power demand also set a new daily record during this period, reaching 7.1 MWh on August 2, 2024.[80] Between 2011 and 2024, summer withdrawals from underground storage grew at a compound annual growth rate[81] (CAGR) of 3.9 percent. By comparison,

[78] https://www.iea.org/commentaries/natural-gas-is-now-stronger-than-ever-in-the-united-states-power-sector
[79] Summer months include June, July, and August.
[80] https://www.eia.gov/todayinenergy/detail.php?id=63404
[81] The compound annual growth rate (CAGR) measures the average annual growth rate over a period of time under the assumption that growth happened at a steady, compounded rate each year.

summer withdrawals grew at a 6.0 percent CAGR from 2020 through 2024. Figure 16 illustrates total summer withdrawals by year, as reported by the EIA.

Figure 16



Summer withdrawals represent the months of June, July, and August of each year

Chart: American Gas Association • Source: Energy Information Administration • Created with Datawrapper

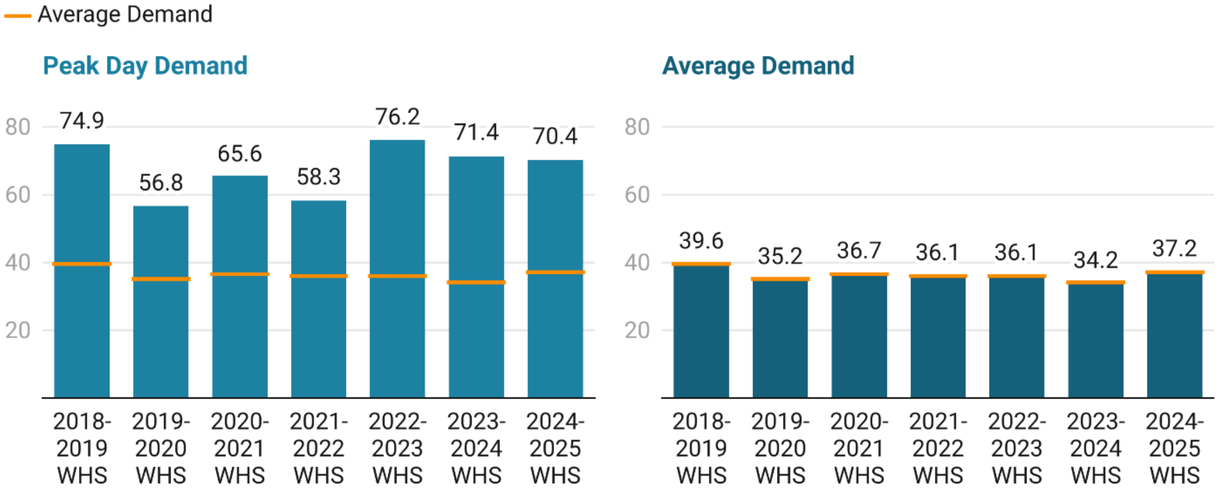
Role in Winter Heating Season Preparation

As with the refill season analysis discussed previously, peak day natural gas demand exceeds average demand during the withdrawal season. Between the 2018-2019 and 2024-2025 winter heating seasons, peak day demand in the residential and commercial sectors was, on average, nearly two times larger than average demand. The spread between average and peak natural gas demands during the heating season was significantly larger than the spread in electric power demand during the cooling season. Figure 17 shows that during this time, peak day demand averaged 67.7 Bcf per day while seasonal average demand averaged 36.4 Bcf per day. However, since 2018, peak day and average demand have fallen by approximately 6 percent each.

Figure 17

Winter Heating Season Residential and Commercial Natural Gas Demand

Billion cubic feet per day (Bcf/d)



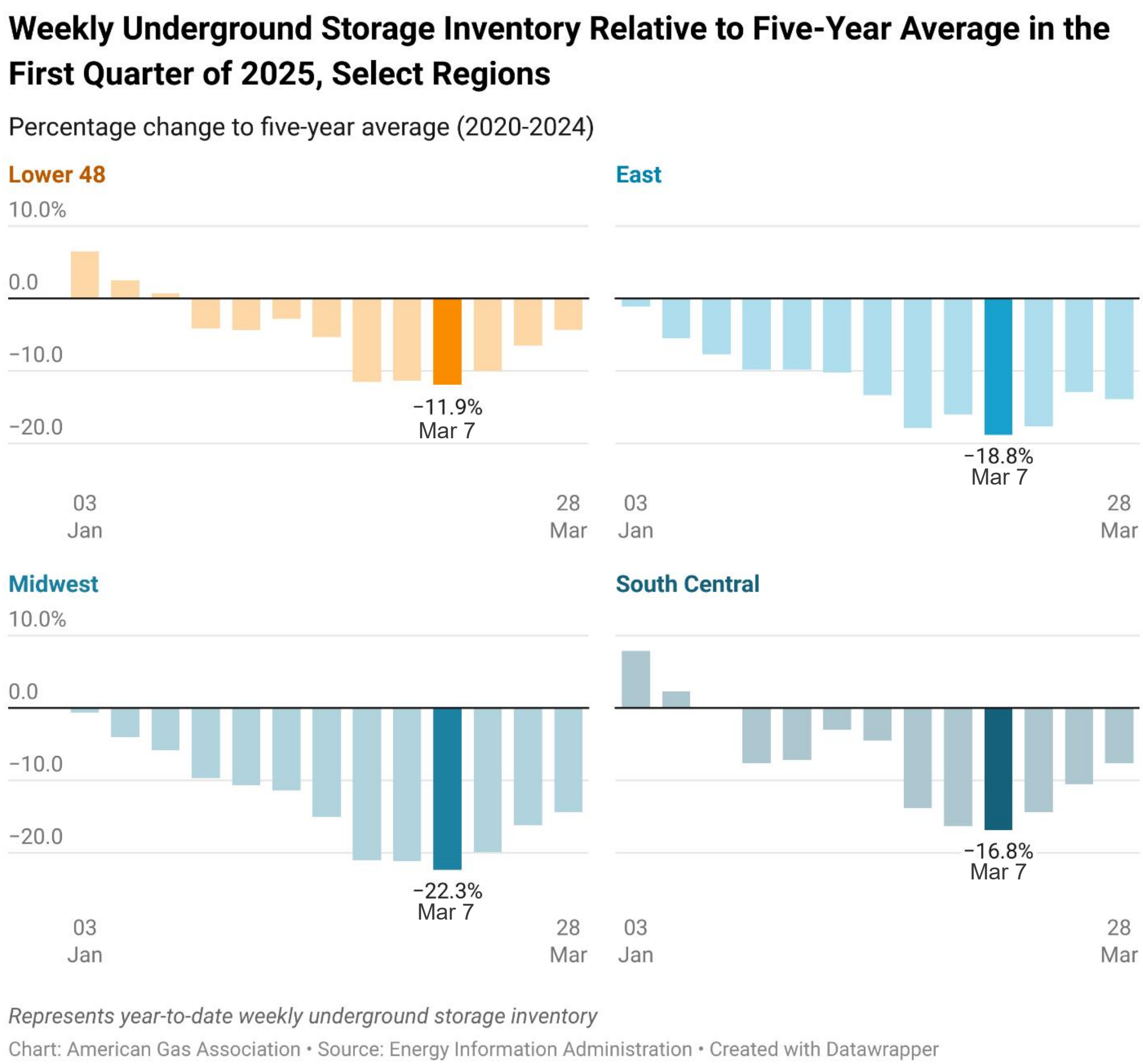
Date ranges reflect November 1 through March 31 of each year.

Chart: American Gas Association • Source: S&P Global Commodity Insights © 2025 by S&P Global, Inc. • Created with Datawrapper

While demand changes over very short periods of time, particularly when temperatures rise and fall abruptly, natural gas producers require planning to ramp up production. Thus, production is usually not immediately responsive to demand signals, meaning that storage is essential to meet short-term fluctuations in winter demand. For example, during the extreme winter weather of early 2025, Winter Storms Blair and Cora unleashed back-to-back snow and freezing conditions between January 4 to 11 from Utah to the East Coast and the western Gulf of Mexico to the Deep South. A week later, an Arctic blast moved through the U.S. from January 19 to 24, bringing freezing temperatures to most states. Between January 20 and 22, Winter Storm Enzo impacted states along the Gulf Coast and Southeast.

In response to the increased need for natural gas to provide essential heat for households and businesses and increased demand in the power sector to generate electricity, underground storage inventory in key regions was heavily utilized. As a result, national inventory levels declined, falling below the five-year average in the first quarter of 2025. Weekly storage data from the EIA showed the decline to be particularly marked in the East and Midwest regions. In certain weeks, inventories in these regions dropped below the minimum of the corresponding five-year inventory range as well. In the South Central region and the lower 48, inventories dipped below the five-year average for the week ending January 24 but remained above five-year minimum inventory levels. Through March 2025, the Midwest experienced the largest deviation in storage inventory relative to the five-year average of more than 22 percent for the week ending March 7. Figure 18 provides a graphical representation of these trends.

Figure 18



To ensure reliable and safe service during these yearly demand spikes, natural gas LDCs develop strategic plans, building carefully crafted supply portfolios using a mix of historic data and modeled forecasts of expected demand loads. Storage is a critical tool in this planning process. According to the AGA's 2022-2023 Winter Heating Season Performance Survey, 97 percent of respondents (36 of 37) used underground storage for a portion of their gas supply during the winter heating season. On average, these 36 LDCs stored 23 percent of their total winter supply portfolio in underground storage.

Additionally, at the aggregate level, LDCs reported using storage for a greater portion of their supply during their peak winter day than during the rest of the winter heating season, when compared to other supply tools. For example, during the peak day, the aggregate volume of gas supply acquired through pipeline or other storage represented 24 percent of the total reported supply, an 11 percentage point increase over the reported share utilized during the rest of the winter heating season. Supply categories, including on-system underground storage and LNG, propane-air (also referred to as liquid propane or LPG), and synthetic natural gas (SNG), also saw an increased use on the peak day in the 1.5 to 3 percent range. Outside of these storage tools, citygate purchases for sale customers increased by 5.4 percentage points, and other supply sources (including linepack and transporter imbalances) increased by 0.2 percentage points. All other supply tools were utilized less during the peak day than during the rest of the winter heating season, indicating the importance of storage assets for service reliability during peak [82]demand events.[83]

System Reliability

The ability to efficiently and quickly draw from natural gas inventories is a cornerstone of energy market reliability and stability. As discussed previously, reliability is an energy system's ability to deliver energy consistently to meet demand requirements and is characterized by low-impact, high-probability events. In fact, "the U.S. energy system manages reliability daily—in the standard fluctuations in energy supply and demand."[84] From normal conditions to severe weather events, withdrawals from storage facilities can compensate for reduced production or increased demand, thereby preventing widespread supply shortages. Such operational flexibility not only bolsters system reliability but also reduces the risk of price spikes.

In addition to providing a buffer against disruptions, storage enables market operators to optimize the timing of gas injections and withdrawals for operational or commercial benefits. Adequate availability of stored natural gas paired with adjacent pipeline delivery infrastructure can help meet demand requirements and reduce price risk for consumers.

Resiliency: Fallback and End-Use Potential

Resilience is characterized by high-impact, low-frequency events. Natural gas storage contributes to a resilient energy system as a fallback option during inclement weather events, such as winter storms, when typical supply routes may be impacted. During extremely cold conditions, natural gas production can experience freeze-offs, a temporary condition when liquids in unprocessed natural gas freeze in equipment at the wellhead, preventing normal flowing production. Freeze-offs can contribute to short-term reductions in dry gas production available to the market. These conditions can be challenging for some consumers, such as electric power plants, that are generally more reliant on spot gas purchases and non-firm transportation services.

[82] Transporter imbalances refer to differences between the amount of natural gas a shipper schedules and the amount delivered or used in a pipeline system.

[83] Disclaimer: The aggregated data presented are not to be interpreted as standards or leading practices for gas supply management but instead represent a snapshot of the aggregated practices of those companies that participated in AGA's 2022-2023 survey. The need for and timing of any of the described practices will vary with each operator based on several factors, including unique regulatory, geographic, and operational characteristics. To learn more about AGA's Winter Heating Season Performance Survey, please visit: https://www.aga.org/research-policy/resource-library/2022-2023-winter-heating-season-performance-survey-overview/.

[84] American Gas Foundation. (2021). *Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience.* https://gasfoundation.org/wp-content/uploads/2021/01/Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf

Storage can prove critical during freeze-offs. For example, if a power plant is co-located with natural gas storage, the power plant can harness that reserve supply during periods of supply constraints. Similarly, stored natural gas can cover supply gaps in the event of a pipeline operator calling on its interruptible customers to reduce demand or even during force majeure events where supply or transportation cannot be maintained.

Natural gas is very useful in a flexible fuel-switching environment when other fuel sources have limited availability and are experiencing their own price spikes. In instances of supply disruptions, natural gas peaker plants with co-located gas storage can play a critical role in promoting energy resilience.

Recent research illustrates the value of natural gas storage for energy system resilience. A 2022 American Gas Foundation (AGF) study found that upstream and downstream investment in both storage facilities and storage distribution infrastructure contributes to natural gas AND electric system resilience.[85] Natural gas storage infrastructure—both above and below ground—has proven invaluable during supply disruptions and demand peaks. As the AGF study shows, it is imperative that adequate pipeline infrastructure be available to interconnect the natural gas system from the storage facility to end-use customers.

Natural Gas Storage Resilience: A Case Study

The following case study is intended to expand on the earlier discussion of the role natural gas storage played during the winter storms and Arctic blast in early 2025, specifically with respect to other extreme weather events, such as wildfires, hurricanes, and winter storms over the last decade.

Much of the U.S. experienced colder-than-normal temperatures in mid-February 2021, when Winter Storm Uri impacted much of the Southwest. Uri affected natural gas production in Texas and nearby areas due to freeze-offs, contributing to production losses of nearly 45 percent in Texas and 21 percent for the U.S. as a whole from the week ending February 13 to February 17.[86] The EIA reported that Uri contributed to production declines of nearly 5 Bcf per day from the Permian region and more than 2 Bcf per day from the Haynesville region.[87] [88] Stored natural gas proved to be a crucial resource during this time. For the week ending February 19, 2021, net withdrawals from underground storage reached nearly 340 Bcf, the second largest reported withdrawal from natural gas storage in the U.S., with a record withdrawal of 156 Bcf occurring in the South Central region that week.[89]

Additionally, supply constraints at this time contributed to rising natural gas prices. The Tuscan LNG Plant in Southern Arizona vaporized and injected more than 10,000 dekatherms of stored gas into the distribution system during Uri, saving Southwest Gas customers $1.5 million over two days.[90] Absent the availability of

[85] American Gas Foundation. (2022). *Enhancing and Maintaining Energy System Resilience: Areas of Focus and Change*. https://gasfoundation.org/wp-content/uploads/2022/10/AGF-Enhancing-and-Maintaining-Gas-and-Energy-System-Resiliency-Report-NOV.pdf
[86] https://www.eia.gov/todayinenergy/detail.php?id=46896
[87] By comparison, Winter Storms Elliott and Heather, which occurred in December 2022 and January 2024, respectively, are estimated to have reduced natural gas production in the Permian Basin by approximately 3 Bcf per day, while Elliott reduced production in the Northeast by more than 6 Bcf per day. *See*: https://www.eia.gov/todayinenergy/detail.php?id=61563
[88] https://www.eia.gov/todayinenergy/detail.php?id=61563
[89] https://www.eia.gov/todayinenergy/detail.php?id=46916
[90] https://www.matrixservicecompany.com/wp-content/uploads/2023/03/LNGIndustry-March2023.pdf

natural gas storage inventory, service outages would have been more widespread, and Southwest Gas customer bills would have been higher.

Winter Storm Elliott affected the Eastern interconnection in late December 2022, impacting the energy system with winter peak loads that caused unplanned outages of 90,500 MW.[91] Additionally, Elliott severely impacted Consolidated Edison Company of New York's (ConEd) natural gas operations during this time. ConEd, the natural gas LDC for Manhattan, the Bronx, and parts of Queens and Westchester County, experienced supply disruptions when the utility's pipeline servicers lost pressure. By preemptively planning for the storm, curtailing supply to interruptible customers, and activating its LNG facility, ConEd was able to maintain its distribution system pressure and was able to serve all homes during the height of the cold weather event. Of note, the LNG facility was dispatched on the afternoon of December 24 and returned to stand-by status the following morning when pipeline pressures began to improve, to preserve inventory.

The Polar Vortex that affected Oregon in February 2014 relied heavily on natural gas storage to maintain service. According to one report, nearly half of the Northwest Natural system peak that occurred on February 6, 2014, was met by storage inventory, "highlight[ing] the critical role that natural gas storage plays in meeting demand during extreme weather events."[92]

While not specific to the Polar Vortex, the winter of 2013-2014 represented the largest drawdown[93] from U.S. natural gas storage to date. By the end of the 2013-2014 winter heating season, storage levels in the lower 48 fell to 822 Bcf for the week ending March 28, 2014, nearly 49 percent below the five-year minimum.[94]

Natural gas storage contributes to system resiliency during hurricanes, droughts, and wildfires as well. In August 2020, Hurricane Isaias affected the energy system along the Atlantic coast from North Carolina to New England. In New Jersey in particular, New Jersey Natural Gas experienced a 60 percent demand increase on its system as residential and commercial customers used natural gas-fueled backup generators during power outages. The Company was able to manage the increased demand via built-in natural gas storage inventory and system flexibility.[95] In California, Southern California Gas Company used its natural gas storage to continue service in August 2020 despite increased cooling demand due to high temperatures and reduced renewable energy generation as a result of wildfires.[96]

Without adequate inventories of underground and LNG storage at these times of critical need, service to power plants, businesses, and homes would have been critically endangered.

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[91] FERC & North American Electric Reliability Corporation (NERC). (2023). *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliot: FERC, NERC, and Regional Entity Staff Report.* https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022

[92] American Gas Foundation. (2021). *Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience.* https://gasfoundation.org/wp-content/uploads/2021/01/Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf

[93] https://www.eia.gov/todayinenergy/detail.php?id=15391

[94] https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2014/04_03/

[95] American Gas Foundation. (2021). *Building a Resilient Energy Future: How the Gas System Contributes to US Energy System Resilience.* https://gasfoundation.org/wp-content/uploads/2021/01/Building-a-Resilient-Energy-Future-Full-Report_FINAL_1.13.21.pdf

[96] *Id.*

Supporting a More Dynamic Energy Landscape

As the energy system evolves and becomes increasingly reliant on natural gas and renewable energy sources, the role of natural gas storage must be considered in the context of broader system needs. This includes not only seasonal balancing and emergency response but also the ability to support increasingly dynamic, flexible operations across the value chain. One of the most pressing structural changes in today's energy mix is the rising share of renewable generation,[97] particularly wind and solar, driven by policy goals, technology advancements, and market evolution. While renewable resources are a necessary tool in an increasingly cleaner grid, the inherent variability and weather dependence of these energy sources place added pressure on the rest of the energy system to remain reliable and responsive, particularly when renewable energy is unable to come online quickly.

Natural gas is uniquely positioned to serve as a balancing tool in this energy environment since it can respond quickly to declines in renewable output and can be stored in LNG tanks near generating facilities. The scope and size of natural gas storage facilities make natural gas storage an unmatched buffer for extreme seasonal peaks and emergency events. Notwithstanding recent significant advances and investment into battery technology, natural gas storage remains a critical enabler of real-time system flexibility.

Table 4 illustrates the estimated daily stored electricity output of both pumped hydro and battery storage compared to natural gas storage. Pumped hydro and battery storage have a combined nameplate capacity of 50 gigawatts (GW) with an estimated combined output of 146.5 gigawatt hours (GWh) per day. On average, current pumped hydro capacity can provide an estimated four hours of electric output per day, while battery storage can provide an estimated two hours of electric output per day. By comparison, actual peak day[98] natural gas output on January 21, 2025, the second-highest daily withdrawal to date, equates to nearly 21,100 GWh per day, 144 times the combined output from all currently existing battery and pumped hydro facilities in the US.

[97] For example, between 2020 to 2024, the portion of electric generation derived from renewable energy sources rose 3.3 percentage points from 19.5 percent to 22.8 percent according to EIA data. By comparison, the portion of generation derived from natural gas remained relatively flat, falling 0.5 percentage points from 39.1 percent to 38.6 percent.

[98] The largest single-day withdrawal occurred on January 1, 2018, and was slightly larger than January 21, 2025.

Table 4

U.S. Energy Storage Capacity and Daily Deliverability by Resource

Based on Maximum Nameplate and Monthly Capacity Factor through January 2025

Resource	Nameplate Capacity (GW)	Avg Hours/Day	GWh/Day
Pumped Hydro	23	4	93.1
Battery	27	2	53.4
Total	50		146.5
Natural Gas Storage		**Bcf/Day**	**GWh/Day**
Peak* Day Output on 1/21/2025		69.4	21,087.70

** Peak day output on January 21, 2025, is the second highest storage withdrawal reported by S&P Global. Subject to revision.*

Table: American Gas Association • Source: Energy Information Administration, S&P Global Commodity Insights © 2025 by S&P Global, Inc. • Created with Datawrapper

Reinforcing the Broader Value of Storage

As discussed earlier, natural gas storage delivers measurable value across the supply chain during both routine and extraordinary conditions. Its ability to reinforce reliability, stabilize markets, and absorb shocks has long been recognized. However, in a system increasingly shaped by variable generation and shifting consumption patterns, storage must also be recognized as a flexible asset that complements the use of renewables and helps bridge the gap between generation and demand.

Viewed through this lens, storage is a critical component of a resilient, adaptable energy system. It supports reliability not only in the face of seasonal or weather-driven challenges, but also as a daily operational tool in a modern, decarbonizing energy landscape. These flexibility attributes represent another layer of strategic value that natural gas storage provides to both natural gas industry and power sector stakeholders by completing the broader picture of storage as a foundational component of system reliability and resilience. Section 5 builds on this discussion of the value of natural gas storage by considering the economic valuation of storage for gas owners. This section discusses both intrinsic and extrinsic market valuation frameworks and describes the regulatory value derived through cost of service regulation.

5. Value of Storing Natural Gas

Natural gas storage facilities require substantial investment, often involving millions of dollars in construction costs and ongoing expenses for system maintenance and operation. To attract capital, storage facility developers must offer investors incentives that outweigh the actual and opportunity costs of the investment. One of the primary incentives for investors is the *value* that natural gas storage brings to the energy market. Thus, the cost-effectiveness of a project hinges on:

- The developer's ability to show that the value the project brings to the market is greater than its cost, and
- Its ability to show that the project's cost-effectiveness is at least as high as the cost-effectiveness of other potential projects with similar risk profiles.

Estimating the value of a project can be a complex task. For a storage facility that charges market-based rates, the valuation of gas storage is generally understood by its *intrinsic* and *extrinsic* values.[99] [100] Intrinsic and extrinsic valuations of gas storage can be modeled, calculated, and analyzed in several ways, but this report offers a generalized discussion of market valuation. For regulated storage facilities, such as those owned and operated by LDCs, valuation is based on a cost-of-service model which will also be discussed in this report.

Market-Based Valuation

Intrinsic Value

Intrinsic value refers to the inherent benefits of a project or contract resulting from the seasonal spread in natural gas prices. The intrinsic value of underground storage can be calculated by evaluating the seasonal spread between summer (injection) and winter (withdrawal) prices.[101] This value can be directly observed and hedged against current forward market prices and allows the opportunity to estimate a storage valuation at the time of injection or withdrawal that is independent of shifting market conditions.[102]

Seasonal price spread refers to differences in natural gas prices between seasons, which tend to follow a predictable yearly pattern. During the refill season, natural gas prices tend to be lower due to higher temperatures and lower demand. Conversely, during the withdrawal season, natural gas prices tend to be higher as colder temperatures drive increased energy demand.[103] The owners of gas in storage capitalize on

[99] Facilities that charge market-based rates are authorized by FERC pursuant to the 2005 Energy Policy Act. *See* Section 3, Jurisdictional Considerations.
[100] Fang, H., Ciatto, A., & Brock, F. (2016). *U.S. Natural Gas Storage Capacity and Utilization Outlook.* https://www.energy.gov/sites/prod/files/2017/01/f34/U.S.%20Natural%20Gas%20Storage%20Capacity%20and%20Utilization%20Outlook_0.pdf
[101] Fang, H., Ciatto, A., & Brock, F. (2016). *U.S. Natural Gas Storage Capacity and Utilization Outlook.* https://www.energy.gov/sites/prod/files/2017/01/f34/U.S.%20Natural%20Gas%20Storage%20Capacity%20and%20Utilization%20Outlook_0.pd
[102] https://www.lacimagroup.com/wp-content/uploads/2020/08/Gas-storage-overview-static-valuation.pdf
[103] Withdrawal season also aligns with the winter heating season months.

seasonal spreads by optimizing the timing of gas storage injections and withdrawals to maximize profit. The larger the seasonal spread, the higher the intrinsic value of storage, as owners can withdraw and sell gas at a premium (a price higher than the price of gas when it was injected).[104]

In the past, large seasonal spreads equated to high intrinsic value for underground storage. However, since the late 2000s, shrinking seasonal spread in the U.S. has diminished the inherent value of gas storage units.[105] The increased use of natural gas for export and during the summer months for electric generation has increased base load demand and reduced seasonal spreads. The shale gas revolution has enabled the shift by greatly increasing domestic natural gas supply since 2000.[106]

FERC's 2011 *State of the Markets* report highlighted factors contributing to declining seasonal spread, stating,

> "[f]alling seasonal spreads reflect increased production and storage capacity, as well as greater year-round use of natural gas by power generators. … [W]e expect this trend to continue."[107]

Since 2011, production and the use of natural gas for electricity generation have continued to climb, while underground storage development has slowed significantly.[108] Despite this sluggish capacity growth, seasonal price spreads have continued to shrink over the last decade. Figure 19 illustrates this trend.

Between 2013 and 2023, the average seasonal spread of natural gas in underground storage was -$0.38 per MMBtu, indicating that futures contract prices during the winter heating season were lower on average than those during the preceding refill season over this period. Winter heating season prices also averaged a negative price differential when compared to refill season prices the decade prior, with an intrinsic value of -$0.27 per MMBtu from 2003-2013. In comparison, the average price of gas during the refill season was lower than the price of gas during the winter heating season between 1994 and 2003, providing an average value of $0.22 per MMBtu.[109]

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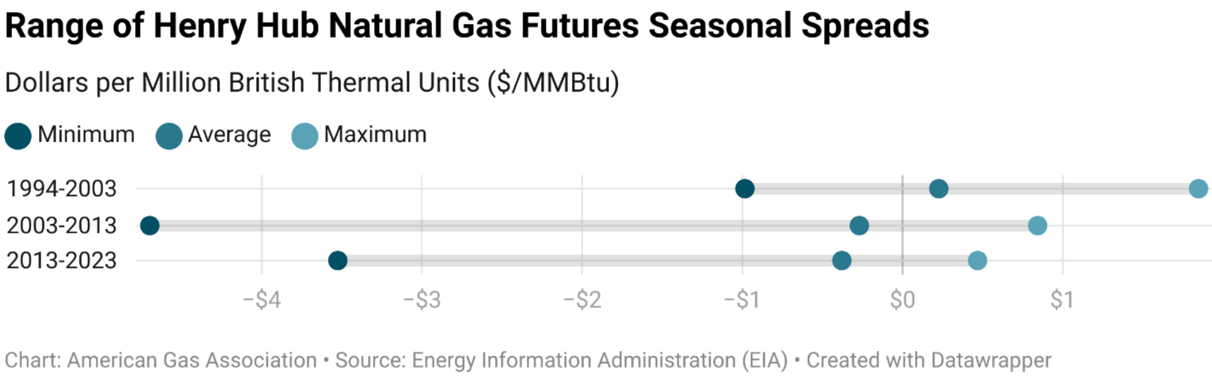
[104] Fang, H., Ciatto, A., & Brock, F. (2016). *U.S. Natural Gas Storage Capacity and Utilization Outlook.* https://www.energy.gov/sites/prod/files/2017/01/f34/U.S.%20Natural%20Gas%20Storage%20Capacity%20and%20Utilization%20Outlook_0.pdf
[105] Hénaff, P., Laachir, I., & Russo, F. (2018). Gas Storage Valuation and Hedging: A Quantification of Model Risk. *International Journal of Financial Studies, 6*(1), 27. https://doi.org/10.3390/ijfs6010027
[106] https://thebreakthrough.org/issues/energy/history-of-the-shale-gas-revolution
[107] https://www.ferc.gov/sites/default/files/2020-05/som-rpt-2011.pdf
[108] See Section 3, Figure 6.
[109] https://www.eia.gov/dnav/ng/ng_pri_fut_s1_m.htm. Note: Values are calculated using Henry Hub monthly natural gas futures contract prices. As of 3/5/3035 available data reflects prices between December 1994 to April 2024.

Figure 19



While the intrinsic value of natural gas is a useful tool in assessing the cost-effectiveness of storage projects, it fails to capture short-term market changes effectively. [110] To account for that deficiency, analysts also look at the extrinsic value of storage.

Extrinsic Value

Extrinsic refers to the option value outside of intrinsic value that can be derived from the flexibility storage assets provide in response to market changes. However, unlike intrinsic value, extrinsic value cannot be observed or hedged at the time of valuation.[111] At its most basic level, extrinsic value is determined by the ability of storage owners and operators to profit from the optionality inherent in storage and the ability to respond to price movements, uncertainty, and volatility.[112] [113] Thus, extrinsic value can be calculated as the incremental value that storage owners can earn by re-optimizing withdrawals and injections according to spot and forward price movements.[114]

Over time, as the shrinking seasonal spread has diminished the intrinsic value of storage, the extrinsic valuation has become increasingly important to facility owners. Storage owners and operators may have a greater opportunity to realize increased extrinsic value when there is high price volatility by selling stored gas into the market when prices rise and injecting gas into storage when prices drop.[115] Figure 20 shows a measure of historical price volatility at Henry Hub equal to the day-to-day percent change in price.[116]

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[110] https://www.gie.eu/wp-content/uploads/filr/2747/GIE_Brochure_The_Value_of_Gas_Storage_May2015.pdf
[111] https://timera-energy.com/blog/a-practical-view-of-the-flexibility-value-of-gas-and-power-assets/
[112] See Section 3, Table 3
[113] https://search.lsu.edu/ces/presentations/2009/DISMUKES_GAS_STORAGE_ENV_PERMIT_1.pdf
[114] Fang, H., Ciatto, A., & Brock, F. (2016). *U.S. Natural Gas Storage Capacity and Utilization Outlook.* https://www.energy.gov/sites/prod/files/2017/01/f34/U.S.%20Natural%20Gas%20Storage%20Capacity%20and%20Utilization%20Outlook_0.pdf
[115] *Id.*
[116] The EIA defines price volatility by the day-to-day percentage difference in the commodity's price. The degree of variation, not the level of prices, defines a volatile market. *See*: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2003/10_23/volatility%2010-22-03.htm

Figure 20

Natural Gas Spot Price Daily Deviation at Henry Hub

Percentage Change

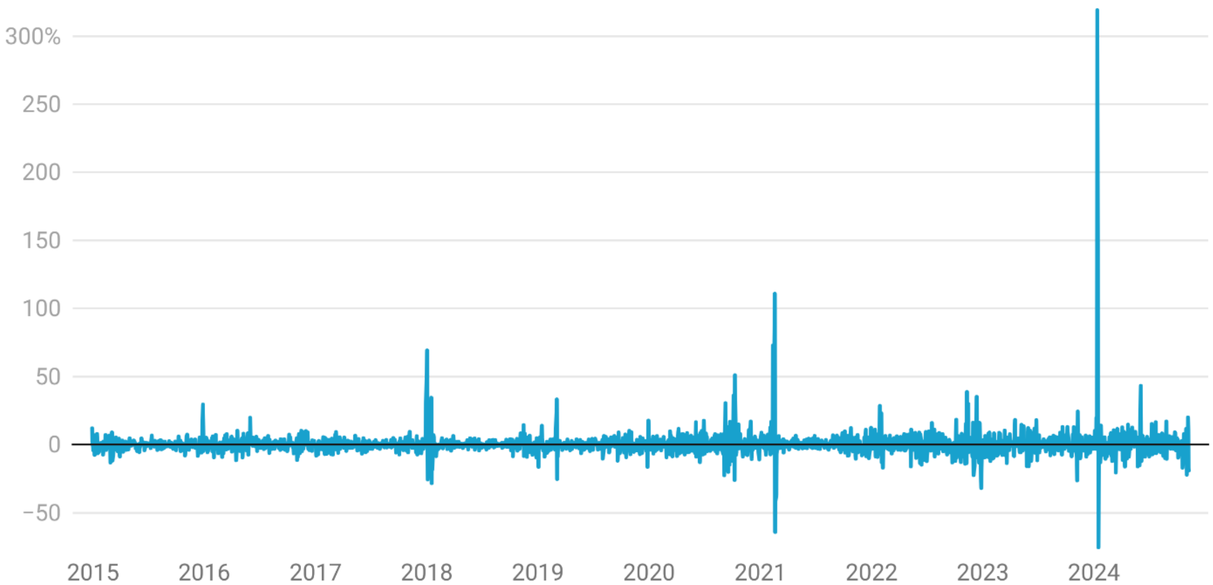
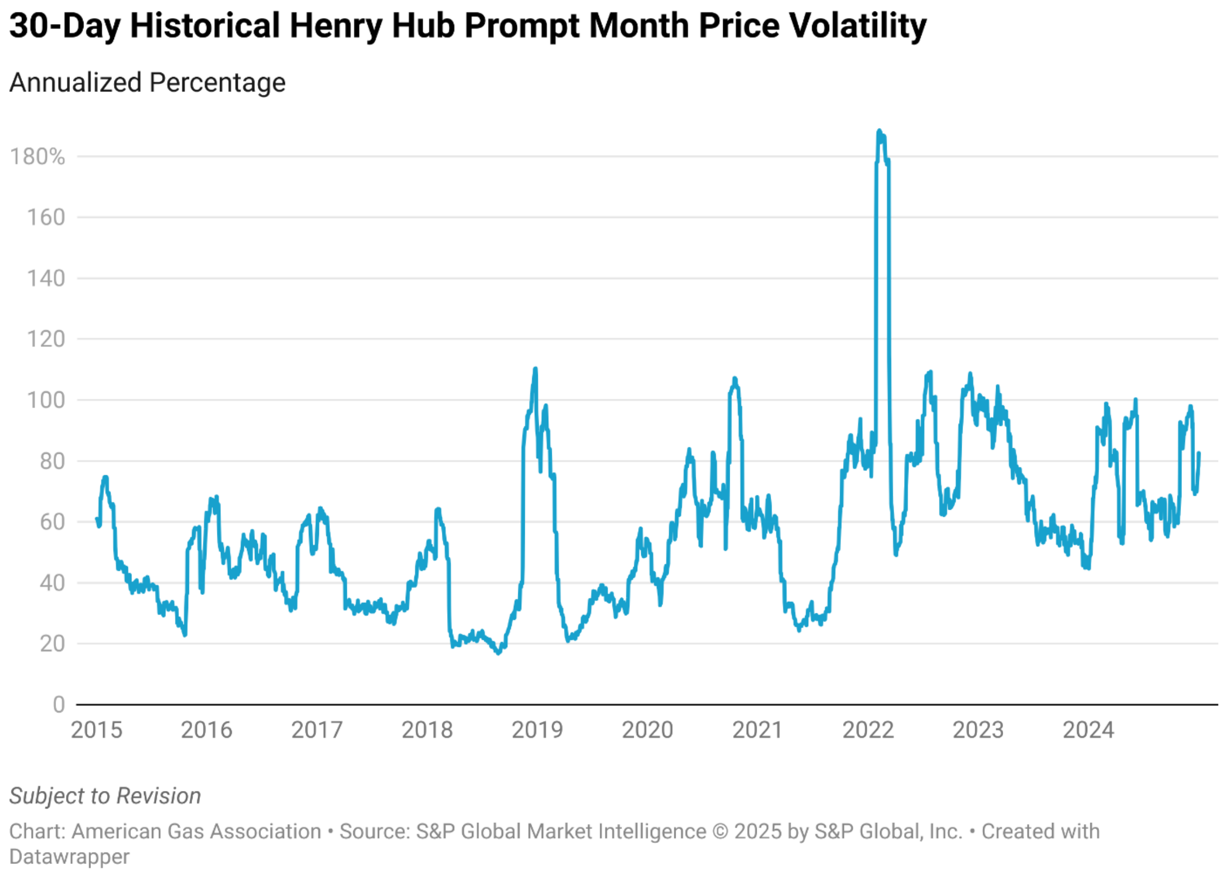


Chart: American Gas Association • Source: Energy Information Administration • Created with Datawrapper

Looking at prompt month prices at Henry Hub in Figure 21, historical volatility has increased between 2015 and 2024. The average annualized percentage between 2015 and 2019 was 43 percent.[117] This measure of price volatility increased over the following five-year period, averaging 71 percent between 2020 and 2024. According to the EIA, price volatility is influenced by increased uncertainty about market conditions that affect natural gas supply and demand (*e.g.* production freeze-offs, storms, changes in inventory levels). In quarter one of 2022, price volatility reached an average of 128 percent due to declining production levels in January and February, weather-driven fluctuations in natural gas demand, record U.S. LNG exports to Europe to help reduce supplies from Russia, and declines in working gas inventories in the lower 48.[118]

[117] Annualized percentage is a widely used trading measure of price volatility. It is calculated by taking the standard deviation for the previous 30 days of daily changes in the Henry Hub front-month futures price multiplied by the square root of 252 (number of trading days in a year) multiplied by 100. Percentages are averages for that period. See: https://www.eia.gov/todayinenergy/detail.php?id=62203
[118] https://www.eia.gov/todayinenergy/detail.php?id=53579

Figure 21



LNG Storage

The same market valuation framework can be applied to LNG storage, although it is not well discussed in academic literature. Since LNG storage assets do not interact with the seasonality of demand in the same way that underground storage does, the intrinsic valuation may not be applicable. However, merchant-owned LNG storage facilities that are authorized to charge market-based rates can be valued extrinsically.

Domestically, LNG storage owners and operators have the same opportunity as underground storage owners and operators to derive value from the flexibility of storage assets in response to market movements. A 2010 report published by Carnegie Mellon University approached "real option" storage valuation from the perspective of storing LNG at regasification facilities.[119] The study attempted to capture the flexibility and strategic value

[119] Real option in this context refers to the opportunity to make strategic decisions by managing physical assets, such as LNG stored at a downstream facility, in tandem with market uncertainty, such as price fluctuations.

LNG storage brings to the market by integrating different modeling techniques, capturing both price and shipping uncertainty.[120]

Regulatory Value

Regulated storage facilities, including underground and LNG, are valued by a cost-of-service model that is largely determined by prudently incurred costs rather than market conditions or the intrinsic/extrinsic framework discussed above.[121] However, it is important to note that certain market influences—such as inflation and interest rates—can affect both costs and the return expected by equity investors. Under this model, storage operators recover capital investments and operating costs through cost-of-service ratemaking. The value is driven by the allowed rate of return, as determined by the regulator, on the facility's rate base, which consists of capital investments, depreciation expenses, and ongoing operating, maintenance, and administrative expenses. Since these factors are determined through regulatory proceedings rather than market forces, the financial value of regulated storage tends to remain stable, supporting reliability and long-term infrastructure investment.

As an example of cost recovery, Virginia Electric and Power Company (VEPCO), a subsidiary of Dominion Energy, received approval from the Virginia State Corporation Commission (VA SCC) in February 2025 to construct and operate an LNG facility at the Brunswick and Greensville County Power Stations. VEPCO anticipates the project will be complete and in service during the fourth quarter of 2027 at an estimated cost of $547 million, which will be recovered in rates charged to customers. As part of its petition, VEPCO described the project as having an estimated 2 Bcf of LNG storage capacity, 15 million standard cubic feet per day (mmscfd) of liquefication capacity, and approximately 500 mmscfd of regasification capacity.[122]

According to the filing, VEPCO stated the facility would address a reliability need and provide value to more than 700,000 homes to mitigate against threats of severe weather, cyberattacks, natural disasters, or other interruptions. At full capacity, the facility could operate both stations at full load for approximately four days or a single station for approximately eight days. As part of its final order, the VA SCC found that the project "would improve reliability of electric service provided by [VEPCO],"[123] "is required by the public convenience and necessity…[in] that it is one way to 'guard[] against anomalous threats to reliability,'"[124] and "can be expected to have a meaningful term of service,"[125] underscoring the inherent value of the project for customers.

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[120] Lai, G., Wang, M. X., Kekre, S., Scheller-Wolf, A. & Secomandi, N. (2010). *Valuation of the Real Option to Store Liquefied Natural Gas at a Regasification Terminal.* https://kilthub.cmu.edu/articles/journal_contribution/Valuation_of_the_Real_Option_to_Store_Liquefied_Natural_Gas_at_a_Regasification_Terminal/6709037?file=12238235

[121] Fang, H., Ciatto, A., & Brock, F. (2016). *U.S. Natural Gas Storage Capacity and Utilization Outlook.* https://www.energy.gov/sites/prod/files/2017/01/f34/U.S.%20Natural%20Gas%20Storage%20Capacity%20and%20Utilization%20Outlook_0.pdf

[122] *See* Virginia Electric and Power Company, Order No. 250230124, Virginia State Corporation Commission. Ordered February 24, 2025. Case No. PUR-2024-00096. https://www.scc.virginia.gov/docketsearch/DOCS/83zm01!.PDF

[123] *Id*. at 11.

[124] *Id*. at 14.

[125] *Id*. at 14.

6. Constraints, Challenges, and Future Outlook

Market Constraints and Challenges

Under the current market landscape, underground and LNG storage assets are critical to maintaining market stability and energy security requirements. Storage owners and operators continuously navigate numerous challenges and constraints, including infrastructure costs, regulatory requirements, pipeline availability, capacity limitations, and consumer needs. As the natural gas industry has evolved and continues to grow, it has become increasingly critical for utilities and storage operators to address and adapt to market limitations and operational changes.

The first hurdle for storage operators is cost. Once a facility has been built, continuous infrastructure investment is required for safety, maintenance, and operation. For gas utility-owned and operated storage, storage infrastructure costs are ultimately passed through to end-use customers. In these instances, developers must ensure that storage investments are prudent and justified by operational needs. For gas utility-owned storage and merchant-owned storage, investment decisions are not limited to new infrastructure. Many underground storage facilities were developed decades ago and require significant ongoing capital investment to maintain and modernize wells and equipment.[126] Newer facilities also need regular maintenance and upgrades in monitoring systems for integrity purposes.

LNG storage facilities also require large capital investments. Operationally, LNG storage is expensive because it must be stored at extremely low temperatures that can only be achieved and sustained through specialized cryogenic technology.[127] In addition, advanced safety systems and continuous regulatory compliance are required to mitigate risk during storage and transport.

Regulatory requirements are an additional consideration for utilities and storage operators. Regulatory frameworks often vary by region and state, complicating the management of multi-state operations due to differences in permitting processes, safety standards, and environmental compliance requirements at the federal and state levels. As a result, LNG and underground storage projects frequently encounter prolonged approval processes that escalate expenses and extend timelines.

Pipeline location and capacity availability present additional challenges for storage users and operators. LNG and underground storage facilities are strategically located near major pipeline systems to facilitate efficient injection and withdrawal and to enable more flexibility through greater market access.[128] The facilities are either integrated into the pipeline system or available at the production or consumption end to help balance flow

[126] U.S. Department of Energy. (2016). *Ensuring Safe and Reliable Underground Natural Gas Storage: Final Report of the Interagency Task Force on Natural Gas Storage Safety.* https://www.energy.gov/sites/prod/files/2016/10/f33/Ensuring%20Safe%20and%20Reliable%20Underground%20Natural%20Gas%20Storage%20-%20Final%20Report.pdf
[127] https://www.wartsila.com/insights/article/creating-optimal-lng-storage-solutions
[128] For more information, see Appendix C.

levels and increase daily pipeline utilization rates.[129] However, downstream pipeline bottlenecks can limit the full ability of storage to access markets and provide value. Bottlenecks occur when existing pipeline capacity is insufficient to transport the necessary natural gas efficiently, whether due to infrastructure limitations, regulatory barriers, geographic constraints, or seasonal congestion during periods of high demand. Pipeline bottlenecks can also lead to regional price spikes, particularly in regions where pipeline expansion and storage additions have not kept pace with demand and production growth.

Like pipeline capacity limitations, the capacity and daily withdrawal limits of natural gas storage facilities pose constraints for LDCs and storage operators that must be planned around and prepared for when building supply portfolios and meeting consumer demand. Assuming pipeline availability, there is a finite supply of natural gas in storage facilities, and only a portion of this gas can be withdrawn from underground storage or regasified from LNG storage in a given period.

Even with adequate storage capacity and deliverability, a lack of sufficient pipeline or delivery infrastructure can limit or prohibit access to storage assets or services. In these cases, regulated pipelines or utilities may struggle to deliver gas from storage when demand is high. This can result in operational challenges for regulated entities and reduced market liquidity for other participants seeking firm transportation or balancing services. In such cases, inadequate access to storage can exacerbate price volatility and limit effective hedging strategies. Therefore, both the physical availability of storage and the infrastructure needed to access it are critical components of system resilience and market efficiency.

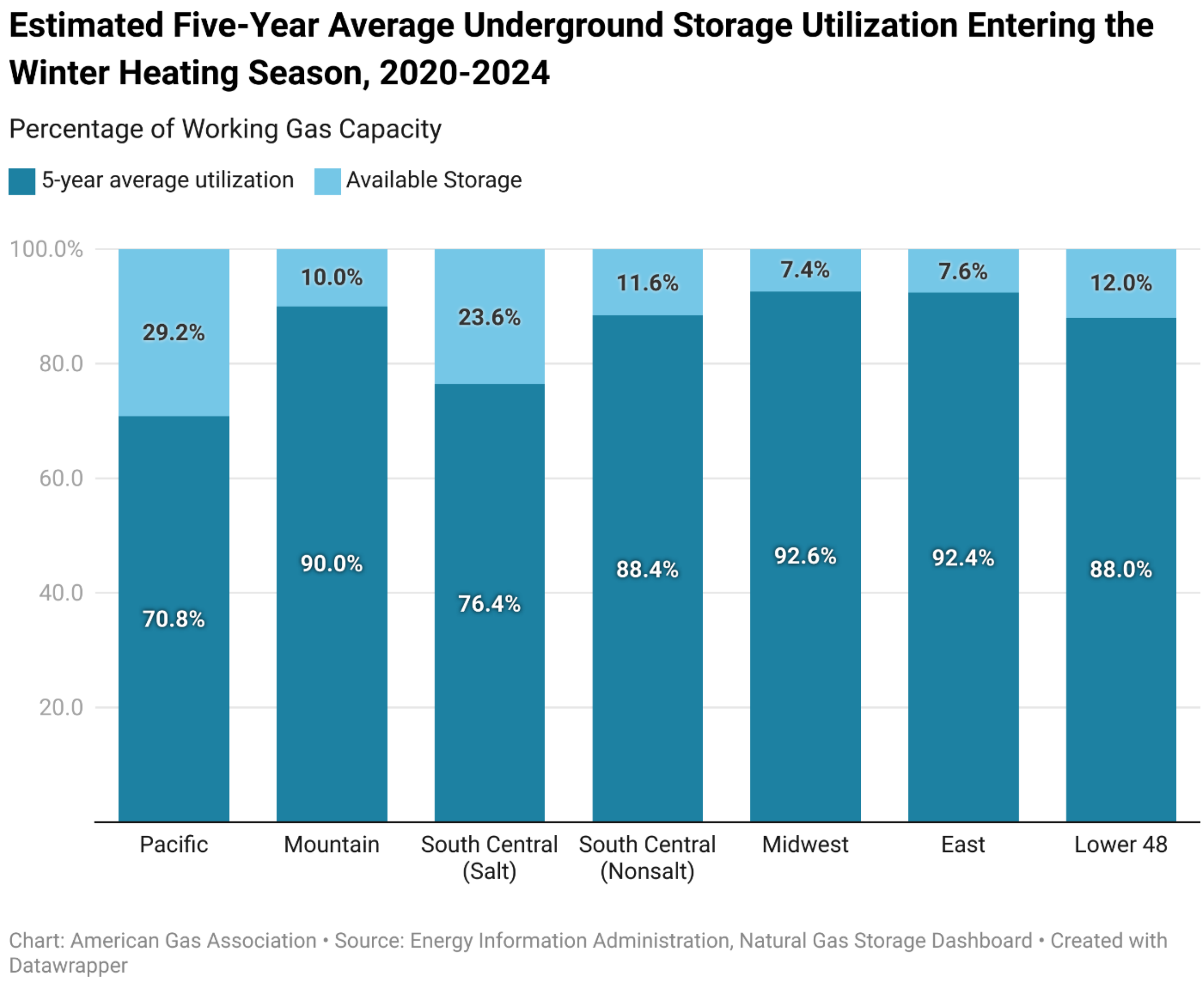
Storage Capacity Analysis

Assessing the need for more storage relies upon current capacity utilization and growth, as well as analyses of production, demand, and pipeline capacity at national and regional levels.[130] The decision to add more storage also depends upon the value additional assets may provide to market participants, whether extrinsic or through efficiency and reliability gains.

Figure 22 depicts the estimated five-year average underground storage capacity utilization in the lower 48 for the week entering the winter heating season each year. From 2020 to 2024, average storage capacity utilization was 88 percent. In the East, Midwest, and Mountain regions, average utilization was at least 90 percent, with yearly maximums ranging between 96 percent and 100 percent.

[129] https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/usage.html
[130] GTI Energy. (2025). *Underground Gas Storage in Natural Gas Infrastructure: Gulf Coast Insights.* https://sagticmsprod01.blob.core.windows.net/gti-cms-prod/2025-01/NZIP_%20UGS%20Report_011025.pdf

Figure 22



Data reflecting the utilization of LNG storage is not publicly available at the same level of detail. However, between 2019 and 2023, U.S. withdrawals averaged 45.4 Bcf per year, 4.2 Bcf lower than the average between 2014 and 2018. Figure 23 shows the five-year average regional withdrawals over the last decade in the lower 48. Between 2019 and 2023, average withdrawals in all regions but the Pacific and South Central were lower than in the previous five years.

Figure 23

Average Annual Withdrawals from LNG Storage, Lower-48

Billion cubic feet (Bcf)

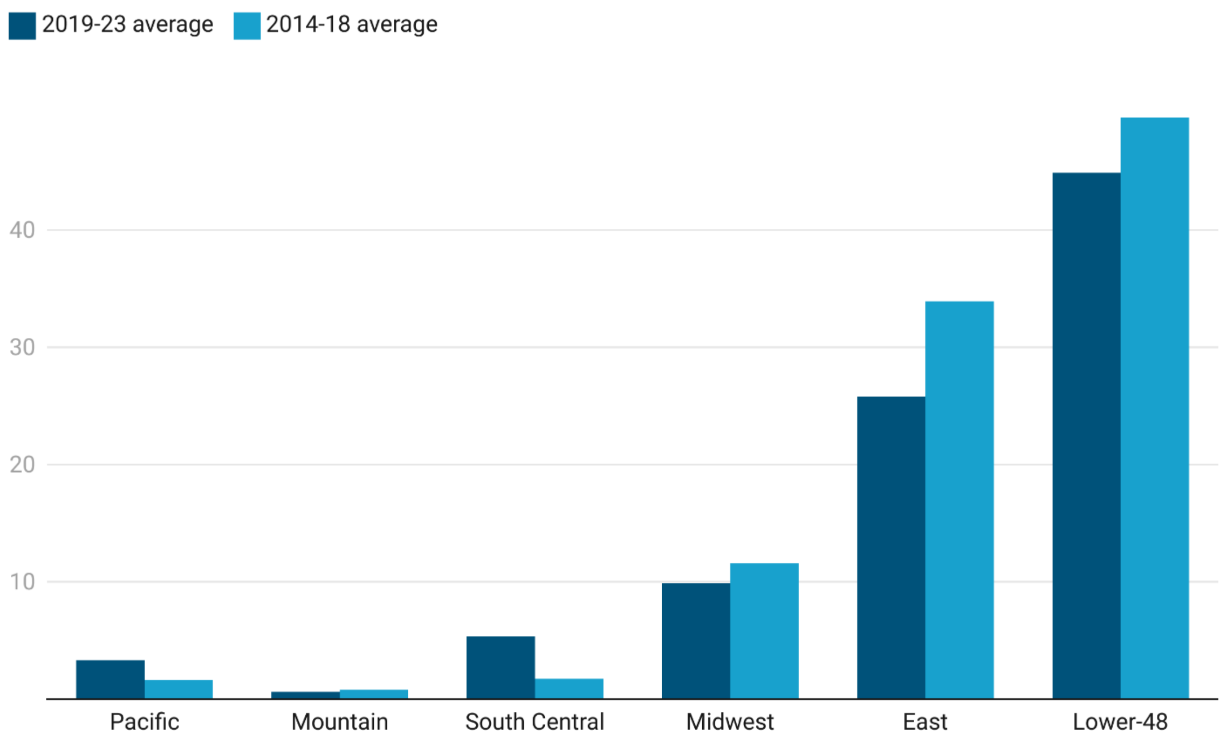


Chart: American Gas Association • Source: Energy Information Administration • Created with Datawrapper

In addition, Table 5 compares the compound annual growth rate of LNG and underground storage capacity with pipeline capacity additions and production and demand growth between 2013 and 2023.[131]

Table 5

Natural Gas Infrastructure and Market Expansion Rates

2013-2023 Compound Annual Growth Rate*

Region	LNG Storage Capacity	Underground Storage Capacity	Intrastate Pipeline Capacity	Interstate Pipeline Capacity	Production	Demand
East	18.3%	0.0%	3.6%	4.6%	11.4%	2.8%
Midwest	0.3%	0.1%	1.6%	6.4%	-3.3%	2.1%
Mountain	7.0%	0.2%	8.7%	1.1%	2.6%	2.4%
Pacific	0.6%	0.2%	0.8%	0.5%	-6.3%	-0.8%
South Central	0.0%	0.2%	6.8%	4.3%	3.0%	2.7%
Lower-48	10.5%	0.1%	5.8%	4.0%	5.0%	2.2%

**LNG Storage Capacity CAGR by region represents 2014-2023*

Table: American Gas Association • Source: Energy Information Administration, Pipeline and Hazardous Materials Safety Administration • Created with Datawrapper

At an aggregate level, dry gas production, demand, and pipeline capacity expansion have outpaced total underground capacity growth over the last decade.[132] This is a clear market signal that additional storage assets may be needed to keep pace with the growth of the market. High seasonal underground storage utilization across the lower 48 also indicates the potential need for expansion, particularly for regions reaching at least 90 percent utilization entering the winter heating season (*i.e.*, East, Midwest, and Mountain). In addition, LNG storage expansion may be necessary in regions where LNG storage capacity expansion has lagged other indicators and the average annual withdrawals from LNG storage have increased over the past five years (*i.e.,* South Central and Pacific). This analysis is not to say that the development and expansion of

[131] For information about the net changes between 2013 and 2023, see Appendix D.
[132] Dry gas is another term for consumer-grade natural gas. This is natural gas that remains after liquefiable hydrocarbons and volumes of nonhydrocarbon gases have been removed. The production of dry natural gas refers to the withdrawal of natural gas from reservoirs, which is reduced by volumes used at the lease site and by processing losses (to make the gas consumer-grade).

LNG and underground storage in other regions is unnecessary; rather, it illustrates where storage may be needed.

Similar to Figure 9 in Section 3, LNG storage capacity CAGRs represent PHMSA data from 2014 to 2023. As noted in Footnote 41, the data reported by PHMSA indicates a sharp decline in in-service LNG storage capacity from 2013 to 2014 despite an increase in the number of in-service facilities. In regions where LNG storage capacity growth has lagged demand and/or production growth, infrastructure expansion is necessary.

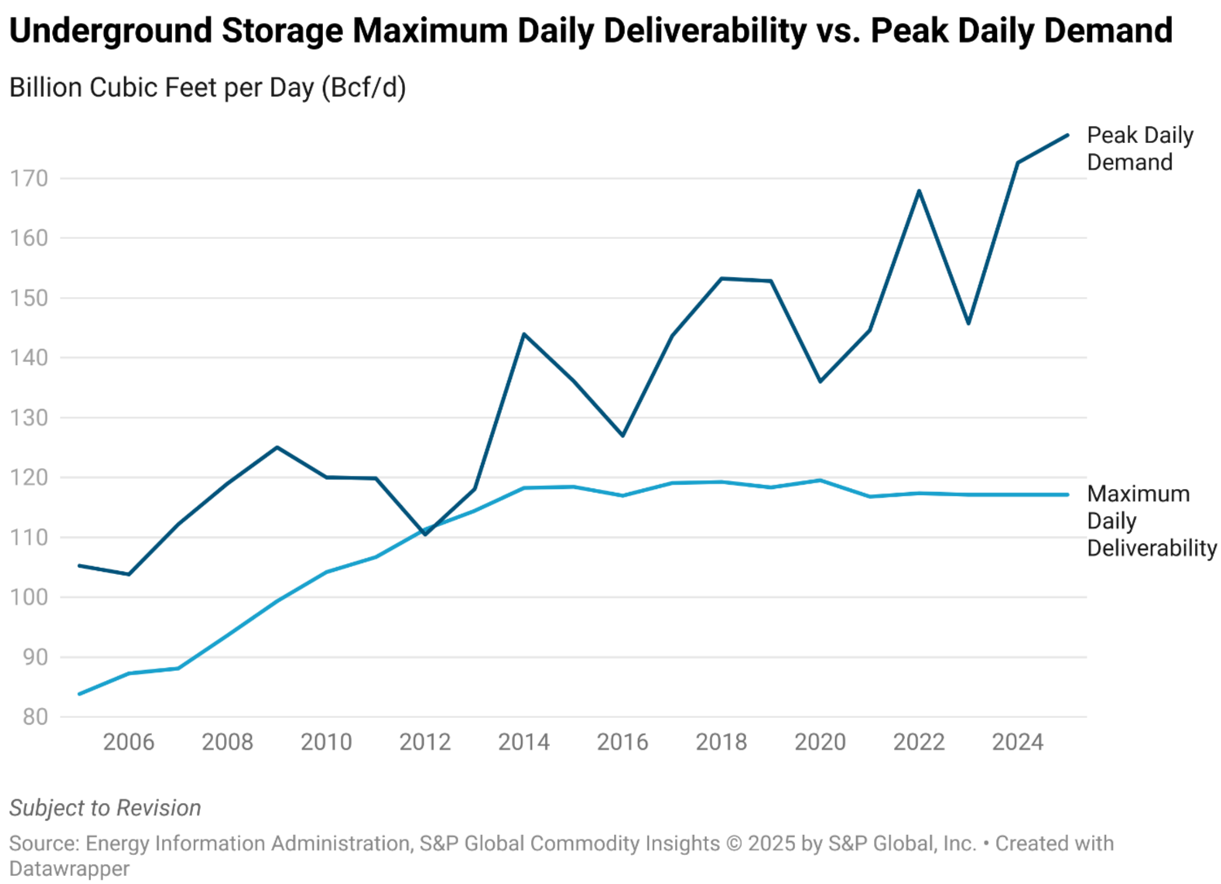
In addition to aggregate growth metrics, analyzing operational dynamics highlights the growing need for additional underground storage. Figure 24 compares peak daily demand with the maximum daily deliverability rate of underground storage for the U.S. over the last two decades. While peak demand has trended upward, deliverability rates have remained relatively flat since 2014, revealing a widening gap between demand and storage availability. In 2005, the difference between peak daily demand and maximum daily deliverability of underground storage assets was 21 Bcf. In 2022, this spread more than doubled to 51 Bcf. By 2025, this gap is expected to reach 60 Bcf, nearly three times the 2005 level.[133]

Since 2005, peak daily demand has increased at nearly twice the rate of maximum daily deliverability, with an average annual peak demand increase of 3.17 Bcf per day and an average annual increase in deliverability of 1.64 Bcf per day.[134] When analyzing the data since 2014, the flattening of the difference in deliverability versus peak demand growth becomes even more marked. Deliverability has been statistically flat over the last decade, while peak daily demand has grown at an annual rate of 3.16 Bcf per day.

[133] Note: The maximum daily deliverability rates for 2024 and 2025 have not yet been published by the EIA's annual 191 report due publishing lags. For the purposes of Figure 24, the deliverability rates for 2024 and 2025 are the same as the most recent report, published for the 2023 year.

[134] Both of these results are statistically significant at the 99 percent confidence level.

Figure 24



Regional Analysis

East: Between 2013 and 2023, capacity additions to LNG storage have soared while underground storage capacity additions have remained stagnant. Currently, no new underground storage projects are planned or proposed in the Eastern region, while approximately 3 Bcf of additional LNG storage capacity is planned.[135] With soaring production levels and growing demand, expanding storage assets in the region will be necessary to meet consumer requirements and to help balance supply and demand.

Midwest: In the Midwest, demand growth outpaced LNG and underground storage between 2013 and 2023. While production levels fell over this period, underground storage utilization reached 96 percent entering the 2024-2025 winter heating season, and LNG storage withdrawals were 9.4 percent higher than in the previous decade. No additional storage assets are planned or proposed in the region as of March 2025, but more storage is needed.

[135] At least one LNG export terminal and one LNG peaker plant have been approved by FERC in the East region. The anticipated capacity represents an estimated volumetric conversion from cubic meters of LNG to Bcf of natural gas. LNG conversion factors may differ based on composition, source, and temperature, which can result in slight variations in the per-volume quantity.

It should also be noted that demand growth outpaced intrastate pipeline capacity additions in the Midwest between 2013 and 2023. Developing additional storage assets will rely on congruent pipeline availability and expansion for local storage utilization, particularly during peak periods.

Mountain: The Mountain region utilized all of its underground storage assets[136] entering the 2024-2025 winter heating season. With underground storage capacity experiencing little growth between 2013 and 2023, this signals the need for more underground storage in the region. Although LNG storage capacity increased over the same decade, growing demand, production, and interstate pipeline capacity levels may also indicate the need for storage expansion, including LNG storage assets. An additional 16 Bcf of underground storage working gas capacity is anticipated in the region by the end of 2025.[137] No LNG storage projects are planned or proposed at this time.

Pacific: Regional regulations have decreased natural gas demand and production in the Pacific region. Nevertheless, the five-year average for LNG storage withdrawals doubled from 2015-2018 to 2019-2023. LNG storage is an important asset for supporting electricity generation reliability in the region, with 90.7 percent of the total LNG storage capacity used for peak shaving. Underground storage also serves as an important backup energy resource in the region. While LNG and underground storage capacity experienced slight growth between 2013 and 2023, additional storage assets will be valuable for supporting grid reliability as electricity demand grows in the region.

South Central: Between 2013 and 2023, demand and dry gas production outpaced underground and LNG storage capacity growth in the South Central region, indicating the need for more storage. As of March 2025, at least 32 Bcf of underground storage working gas capacity has already been added to the South Central region, and 204.5 Bcf more is anticipated by 2031.[138] Additionally, an estimated 150 Bcf of LNG storage at export facilities is planned, proposed, or in construction.[139] Additional peak shaving facilities may also be valuable to help support domestic meet market expansion metrics.

Future Outlook

Market Fundamentals

In 2023, the U.S. natural gas market set new records for both production and consumption, and these trends are largely expected to continue in the near term. However, storage capacity—both underground and for LNG—has remained effectively static, a situation that could pose ongoing issues for supply-demand balances since, as described before, in the short term natural gas production lags demand. Natural gas storage growth may be needed as natural gas production and export technology continue to develop and improve.

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[136] As defined by the EIA's peak demonstrated capacity as of November 2023. *See* Section 3, Figure 5.
[137] Data from S&P Global Commodity Insights. Anticipated additional storage in the Mountain region includes 10 Bcf in construction in Wyoming and 6 Bcf under regulatory application in Utah.
[138] Data from S&P Global Commodity Insights. The anticipated 2031 total represents storage projects that have been announced, are in construction, are in open season, are partially online, or are in the regulatory application process. Only 48 Bcf of additional storage capacity has been confirmed (*i.e.* in construction, announced, or partially online) in the South Central region.
[139] LNG conversion factors may differ based on composition, source, and temperature, which can result in slight variations in the per-volume quantity.

Recent natural gas demand growth has been attributed to increased requirements for gas-fired electric generation, industrial reshoring, and to meet residential and commercial customer additions (on average, more than one new natural gas consumer was added per minute in 2023).[140] Growing demand for natural gas in the power sector and rising LNG exports may lead to new market dynamics or operational realities by which natural gas storage can provide value. The expansion of artificial intelligence and cloud computing services is an additional driver of domestic demand growth.

Across the U.S., the EIA has attributed the recovery of electricity demand in the commercial sector following the pandemic to the acceleration of data center growth, as natural gas demand growth is concentrated among states where data centers are rapidly expanding. In Virginia, electricity demand grew by 14 billion kilowatt-hours between 2019 and 2023. Over the same time period, 94 new data centers were brought online.[141] Additionally, in the first half of 2024, more than 500 megawatts of new data centers were constructed in the U.S. and Canada, increasing inventory by 10 percent and surpassing last year by 23 percent.[142]

Global demand growth is also expected to influence U.S. LNG exports. In the near term, U.S. LNG exports to Europe are expected to increase after significant drawdowns in European inventories during the 2024-2025 winter. As of March 31, 2025, storage inventories in the European Union (EU) were 33.6 percent full, 11.6 percentage points below the five-year average.[143] By November 1, 2025, European Commission targets require EU gas storage inventories to be 90 percent full.[144] Analysts estimate that Europe may need more than 250 extra LNG cargos, estimated to cost at least $11 billion in total, to reach this requirement.[145]

The EIA projects that gross LNG exports will increase by nearly 38 percent through 2026 relative to 2024 levels, aided by the commissioning of new LNG export terminals.[146] The EIA forecasts that LNG export capacity for North America could more than double by 2028, with the bulk of that growth attributable to U.S. LNG export terminal projects.[147] In the U.S., these terminals would add an additional LNG storage capacity of approximately 45 Bcf. An additional 65 Bcf of LNG storage at export facilities in the lower 48 has also been approved by FERC, and approximately 42 Bcf more is proposed or have applications pending.[148] Additionally, gross pipeline exports are expected to increase more than 15 percent from 2024 to 2026 due to new transmission lines such as the Matterhorn Express Pipeline, which was designed to move natural gas produced in the Permian Basin.[149]

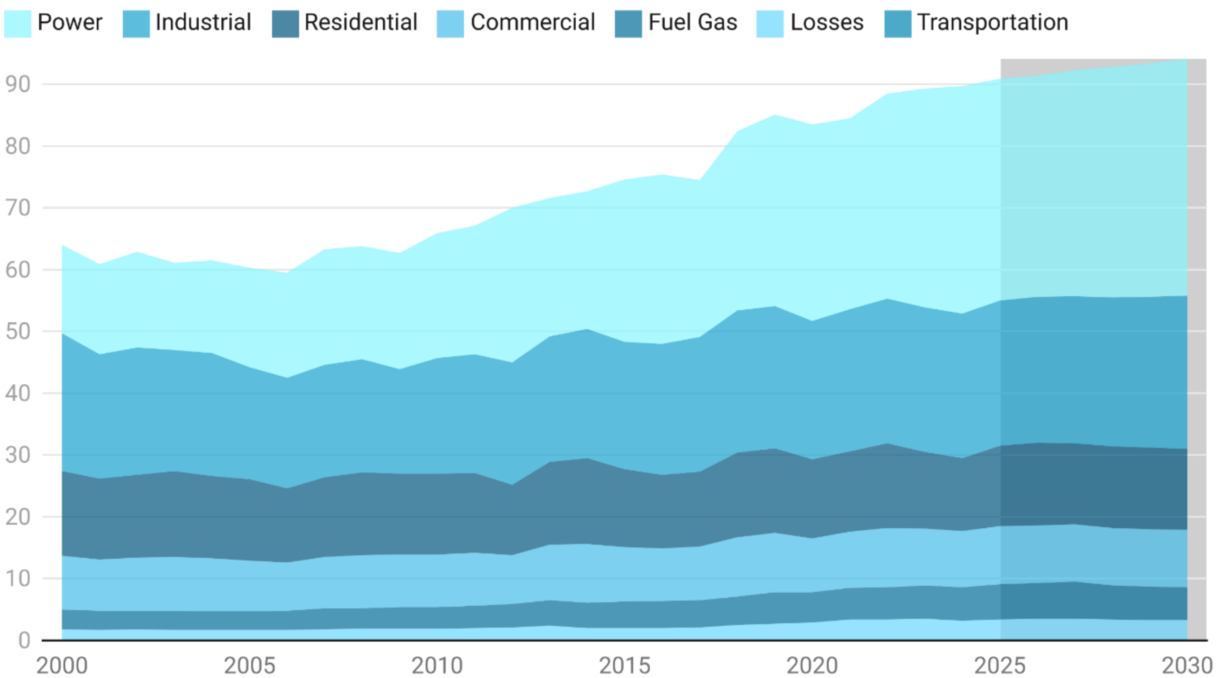
[140] https://playbook.aga.org/
[141] https://www.eia.gov/todayinenergy/detail.php?id=62409; https://s2.q4cdn.com/510812146/files/doc_financials/2024/q1/2024-05-02-DE-IR-1Q-2024-earnings-call-slides-vTC.pdf
[142] https://www.cbre.com/insights/reports/north-america-data-center-trends-h1-2024
[143] https://energiedashboard.admin.ch/gas/eu-gasspeicher
[144] The targets were set to help prevent supply shortages following Russia's invasion of Ukraine in 2022
[145] https://www.reuters.com/world/europe/europe-could-need-extra-11-billion-gas-refill-winter-stores-2025-04-01/
[146] According to the EIA's March 2025 Short-Term Energy Outlook.
[147] https://www.eia.gov/todayinenergy/detail.php?id=62984
[148] LNG conversion factors may differ based on composition, source, and temperature, which can result in slight variations in the per-volume quantity
[149] According to the EIA's March 2025 Short-Term Energy Outlook.

The trend of increased natural gas demand is expected to continue through at least 2030. Rystad Energy forecasts that total domestic natural gas consumption will increase by 4.5 Bcf per day, or 5 percent, from 2024 to 2030. Figure 25 graphs this demand forecast.

Figure 25

U.S. Domestic Natural Gas Demand Outlook

Billion Cubic Feet per Day (Bcf/d)



Shaded region represents forecast

Chart: American Gas Association • Source: Rystad Energy, North America Medium-Term Gas Outlook • Created with Datawrapper

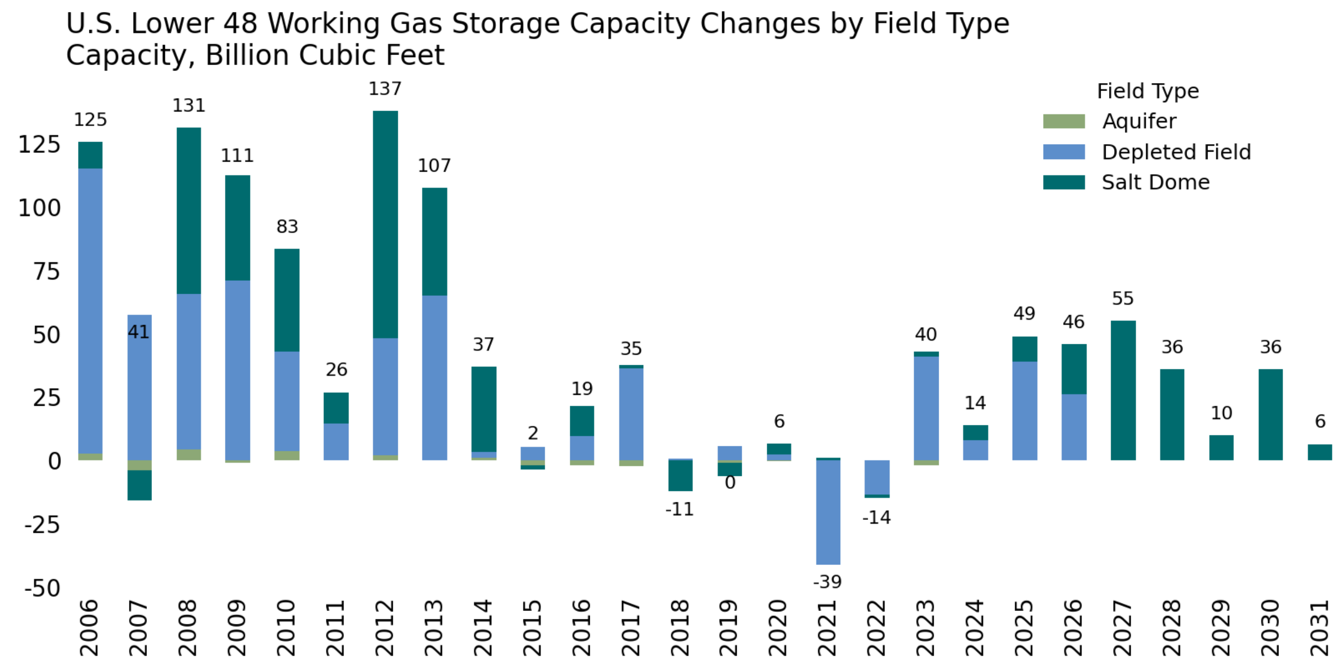
Natural gas is widely perceived to be a critical energy resource to meet data center energy load growth going forward. S&P Global Ratings estimates that by 2030, U.S. data centers will increase gas demand by between 3 and 6 Bcf per day. Increased demand could lead to supportive financial performance. S&P Global indicated that increased natural gas demand for data centers “should also generally support the [financial] performance of midstream companies focused on natural gas transportation and storage.”[150] Similarly, the International Energy Agency said that “natural gas is set to continue to dominate the near-term data centre electricity supply in the United States,” indicating growth of approximately 130 Terrawatt-hours per year of new natural gas-fired

[150] https://www.spglobal.com/ratings/en/research/articles/241022-data-centers-more-gas-will-be-needed-to-feed-u-s-growth-13290987

electricity generation to serve data centers between 2024 and 2030. This could translate into an additional 2.5 to 3.5 Bcf per day of natural gas demand.[151]

S&P currently tracks 253 Bcf[152] of additional underground storage capacity changes between 2024 and 2031, as shown in Figure 26.[153] Most of these are either depleted fields or salt dome facilities located along the Gulf Coast or Southeast, co-located with new pipeline capacity and production to serve growing LNG export demand. As mentioned in the previous subsection, there are currently no announced projects for new storage capacity additions in the East, Pacific, or Midwest regions.

Figure 26



Source: S&P Global Commodity Insights, ©2025 by S&P Global Inc., Chart: American Gas Association, Data as of Apr 27, 2025, Subject to Revision

Geopolitical Shifts

Geopolitical factors will continue to shape the future of natural gas storage, particularly as the global energy landscape becomes more interconnected. Ongoing conflicts, such as the war in Ukraine, have accelerated the shift in global natural gas trade flows, with European countries seeking to diversify their supply sources and reduce dependence on Russian gas. In 2021, the year before Russia invaded Ukraine, Russian pipeline supply accounted for 31 percent of the gross European gas supply. Russian pipeline exports to Europe have fallen greatly since then, accounting for just 9 percent of the gross European gas supply in 2024.[154] U.S. LNG has

[151] *See* Section 2.5.3: https://iea.blob.core.windows.net/assets/dd7c2387-2f60-4b60-8c5f-6563b6aa1e4c/EnergyandAI.pdf
[152] Please note: total capacity changes may not foot due to rounding.
[153] Note: S&P indicates that 32 Bcf of this total capacity is online. The remaining 221 Bcf represents storage projects that have been announced, are in construction, are in open season, are partially online, or are in the regulatory application process.
[154] Sharples, J. (2025). *The End of Russian Gas Transit via Ukraine: Immediate Impact and Implications for the European Gas Market in 2025*. The Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2025/01/Insight-162-The-End-of-Russian-Gas-Transit-via-Ukraine.pdf

aided Europe in narrowing its energy gap, accounting for 45 percent of the continent's imports in 2023, more than any other country. Demand for U.S. LNG will likely continue to grow as the EU seeks to phase out all Russian gas imports by 2027.[155]

The ability to meet growing global LNG demand in the U.S. will be limited by LNG export capacity and, more specifically, the amount of LNG able to be loaded onto ships for export. Additional storage at LNG export facilities will be crucial to help meet this demand, promoting the continuous run of liquefaction trains while export ships load at the terminal or while the dock awaits empty cargo ships.

Regulatory Developments

Regulatory developments at the federal and state levels will also influence the trajectory of natural gas storage. FERC and the DOE are central to approving new storage and LNG infrastructure, and their policies can significantly impact project timelines. While the Biden Administration froze LNG export terminal permit approvals in 2024, the Trump Administration lifted the freeze in January 2025. The reversal allowed LNG export approvals to continue, as several projects have been approved by the DOE since the policy was rescinded. In April 2025, the DOE also lifted another Biden-era policy requiring authorized LNG exporters to meet strict criteria before being considered for LNG project timeline extension.[156]

Another regulatory consideration is the long timelines often required to permit, site, and construct natural gas storage facilities, sometimes involving multi-year approvals. Overlapping agency jurisdictions, public opposition, and complex environmental permitting processes can delay regulatory reviews. In today's rapidly shifting energy environment, this lag between planning and operational readiness can limit the system's ability to respond to emerging supply-demand pressures. These pressures must be balanced by other considerations, including public engagement and regulatory due diligence. However, to improve system flexibility and long-term resilience, there is a growing need for permitting reform that streamlines and accelerates the approval process for essential storage infrastructure. Reforms could include clearer permitting timelines, coordination between state and federal agencies, and expedited review of projects supporting reliability, grid stability, or critical export capacity. Addressing these challenges will be essential to help ensure that storage development can keep pace with rising demand.

Differences in state policy toward natural gas could lead to uneven treatment in storage infrastructure. Increased variable renewable electricity may lead to new requirements for flexible generation resources, including natural gas, as demonstrated in Table 4. However, states with aggressive decarbonization or renewable energy targets may also erect regulatory barriers to block or disincentivize the development of new natural gas storage, or even incentivize the removal of existing storage, even as those same policies put additional pressure on the natural gas system. Thus, regulatory barriers to natural gas storage can increase strains on energy system reliability and resiliency. By contrast, other states with high demand or production

[155] https://www.gisreportsonline.com/r/russian-gas/
[156] https://www.energy.gov/articles/energy-department-takes-action-remove-barriers-requests-lng-export-commencement-date

may continue to support storage expansion to meet growing requirements. This regulatory patchwork could further regional disparities in storage availability and market flexibility.

States and other jurisdictions with ambitious emissions reduction targets can also examine how natural gas storage can enable low-carbon pathways. By thinking of storage not simply as a buffer for gas supply, but as a multi-purpose flexibility tool that can unlock decarbonization pathways. Natural gas storage smooths out the variability of wind and solar by providing a firm, dispatchable backup when weather-dependent generation dips. Moreover, underground storage can be utilized for renewable natural gas storage derived from biogenic sources (landfill gas, agricultural digesters), which often have seasonal production peaks. In future scenarios, natural gas storage could possibly be repurposed for hydrogen-ready capabilities. Excess renewable electricity (e.g., midday solar or windy nights) can be converted via electrolysis into hydrogen or synthetic methane, then stored.

Pricing signals can spur new storage development, whether upgrades to existing facilities or new construction. However, several other barriers may slow market development, including permitting timelines, construction costs, and regulatory uncertainty. Addressing these burdens, along with adequate pricing signals from the market, could incentivize additional investment in storage in these areas.

7. Conclusions

Natural gas storage is a foundational component of the U.S. energy system, enabling reliability, flexibility, and resilience in the face of growing domestic demand and shifting global energy dynamics. As demonstrated throughout this report, storage plays a critical role in balancing seasonal supply and demand, enhancing grid reliability, and serving as a strategic buffer during high-impact events such as extreme weather or supply disruptions. Both underground and LNG storage systems serve complementary functions in supporting power generation, industrial processes, residential heating, and international trade.

Despite its indispensable value, natural gas storage faces significant challenges. Aging infrastructure, high capital costs, regulatory complexity, and pipeline bottlenecks continue to constrain expansion and optimization. Additionally, while the value of storage has evolved from a reliance on seasonal price spreads to increased dependence on market responsiveness, many regions in the U.S.—particularly the East, Midwest, and Mountain—are experiencing storage capacity constraints that have not kept pace with the rapid growth in production, demand, and pipeline infrastructure. As electrification accelerates and data center energy needs rise, these storage limitations could exacerbate volatility and reliability concerns.

Looking ahead, robust investment in both underground and LNG storage is essential to maintain system efficiency and meet future energy needs. Regulatory reform that streamlines permitting processes, coordinates agency oversight, and incentivizes strategic storage development will be key to addressing these limitations. Integrating storage with intermittent renewables can also bolster grid stability and support decarbonization efforts, positioning storage as a bridge to a cleaner, more resilient energy future.

Limitations and Opportunities for Further Exploration

While this report provides a comprehensive assessment of natural gas storage infrastructure, market dynamics, and policy frameworks, there are important limitations to note. Publicly available data on LNG storage capacity, utilization, and facility-level operations remain limited and inconsistent, complicating efforts to evaluate regional needs and investment potential. In addition, this report does not fully account for the potential impacts of decarbonization policies, emissions regulations, and carbon pricing mechanisms on future storage economics and system planning.

Regional and local market analyses can pinpoint where additional storage may deliver the greatest strategic value and reveal how market participants currently price existing assets. By comparing realized actual market indicators, such as injection/withdrawal behaviors or storage market rates, stakeholders can spot underserved markets, optimize capacity deployment, and sharpen commercial strategies. These insights also equip regulators and policymakers to target infrastructure investments and regulatory reforms that uphold reliability and advance other goals.

Future research could explore improved methods for valuing storage beyond traditional intrinsic and extrinsic frameworks, including environmental and social benefits. Further analysis is also needed to evaluate the optimal integration of natural gas storage with renewable energy sources, hydrogen blending, and carbon capture technologies. Storage can also be evaluated for its “resilience dividend,” referring to the additional value storage provides during periods of extreme conditions or disruption. Stress-testing supply–demand balances against extreme cold snaps, pipeline outages, or rapid renewable ramp events shows how incremental storage capacity bolsters system reliability, unlocks deeper wind and solar integration, and lays the groundwork for low-carbon pathways. These findings are critical inputs to energy-policy design, market rules, and incentive frameworks that will sustain a flexible, resilient, and increasingly decarbonized energy system.

Final Thoughts

This paper has demonstrated the value of natural gas storage in the market, the vital role of storage in providing system reliability and resilience, and other market considerations. As the U.S. energy landscape evolves, with increased penetration of intermittent renewable energy sources and growing demand for energy security, the role of natural gas storage is expected to become even more significant. Investments in storage infrastructure and technology are critical for maintaining the reliability of natural gas supplies in an increasingly complex and dynamic market. Overall, natural gas storage remains an indispensable component of the nation’s energy strategy, helping to safeguard consumers against disruptions and ensuring a resilient energy system.

Appendix A – Abbreviated Terms

AGA – American Gas Association

AGF – American Gas Foundation

Bcf – Billion cubic feet

CAISO – California Independent System Operator

CNG – compressed natural gas

DOE – Department of Energy

DOT – Department of Transportation

EIA – Energy Information Administration

FERC – Federal Energy Regulatory Commission

FSU – floating storage unit

LDC – local distribution company

LNG – liquified natural gas

MARAD – Maritime Administration

MMcf – Million cubic feet

PHMSA – Pipeline and Hazardous Materials Safety Administration

PUC – Public Utility Commission

USCG – United States Coast Guard

WHS – winter heating season

Appendix B – Glossary of Key Terms

Citygate – the point where natural gas is transferred from an interstate or intrastate pipeline to a local natural gas utility.

Co-location – the practice of placing natural gas storage facilities at or near generation facilities to serve as backup supply.

Compound annual growth rate (CAGR) – measures the average annual growth rate over a period of time under the assumption that growth happened at a steady, compounded rate each year.

Cushion gas – the gas that remains in the storage reservoir as a permanent inventory.

Demonstrated peak capacity – as used by the EIA, the sum of the largest volume of working natural gas reported for each individual storage field during the most recent five-year period, regardless of when the individual peaks occurred.

Depleted fields – refers to depleted oil or natural gas fields.

Design capacity – as used by the EIA, the sum of the reported working natural gas capacities of active storage fields in the lower 48 states as reported on Form EIA-191 as of the end of the most recent five-year review period. Sometimes referred to as nameplate capacity, design capacity is based on the physical characteristics of the reservoir, installed equipment, and operating procedures on the site.

Design day – the coldest hypothetical winter day when demand is expected to reach its highest peak. Natural gas utilities use the design day as a tool for system planning and winter heating season preparation.

Dry gas – another term for consumer-grade natural gas. This is the natural gas that remains after liquefiable hydrocarbons and volumes of nonhydrocarbon gases have been removed.

Dry gas production – the withdrawal of natural gas from reservoirs, which is reduced by volumes used at the lease site and by processing losses to make the gas consumer-grade.

Citygate – is generally the point where natural gas is transferred from an interstate or intrastate pipeline to a local natural gas utility.

EIA Form 191, *Monthly Underground Gas Storage Report* – provides data on the operations of all active underground storage facilities. Data are collected and mandated under Title 15 U.S.C. § 772(b).[157] The data appear in EIA publications such as the annual field-level storage report and the peak demonstrated capacity report.

Feedgas – the amount of natural gas delivered via pipeline to liquefaction facilities to be converted to LNG.

[157] https://www.eia.gov/survey/form/eia_191/instructions.pdf

Floating Storage Regasification Units (FSRUs) – FSUs that combine LNG storage with built-in regasification systems.

Floating Storage Units (FSUs) – ships and barges used as a form of LNG storage by the offshore industry and at LNG import and export terminals.

Injection rate – the rate at which gas is injected into a storage facility.

Injection season – the period of time from April 1 through October 31 of each year during which natural gas is generally injected into underground storage for future use.

Linepack – the amount of gas stored in the pipes of the gas transmission or distribution system.

Lower 48 – refers to the 48 contiguous states of the U.S., excluding Alaska and Hawaii.

Merchant operators – private companies or entities that own gas in storage for commercial, profit-driven purposes rather than for regulatory, utility, or system-balancing obligations.

Merchant Storage – refers to pipeline and independently owned facilities.

Peaker plant – a power plant that operates mainly during periods of high electricity demand, known as peak demand periods.

Peak shaving – a strategy that aims to reduce energy usage during periods of peak demand to promote energy system integrity and resilience. Peak shaving can take many forms, including demand response, energy efficiency, interruptible service, and, in the case of the electric grid, direct use natural gas service.

Pipeline capacity – the maximum amount of gas that can flow through a pipeline at one time.

Propane-air – also referred to as liquid propane or LPG, propane-air is a gas mixture that mimics the properties of natural gas, allowing it to be used as a direct replacement in burners and other combustion equipment without modifications.

Regasification – the process of converting LNG back to its gaseous form.

Reliability – the ability of the energy system to deliver services in the quantity and with the quality demanded by end users. A reliable system responds adequately to high-probability, low-impact events and disruptions.

Resilience – the ability of the energy system to prevent, withstand, adapt, and recover from a system disruption. A resilient system responds effectively to low-probability, high-impact events.

Synthetic Natural Gas (SNG) – synthetic fuel created by mixing vaporized propane (*i.e.*, LPG) with air.

Transporter imbalances – differences between the amount of natural gas a shipper schedules and the amount delivered or used in a pipeline system.

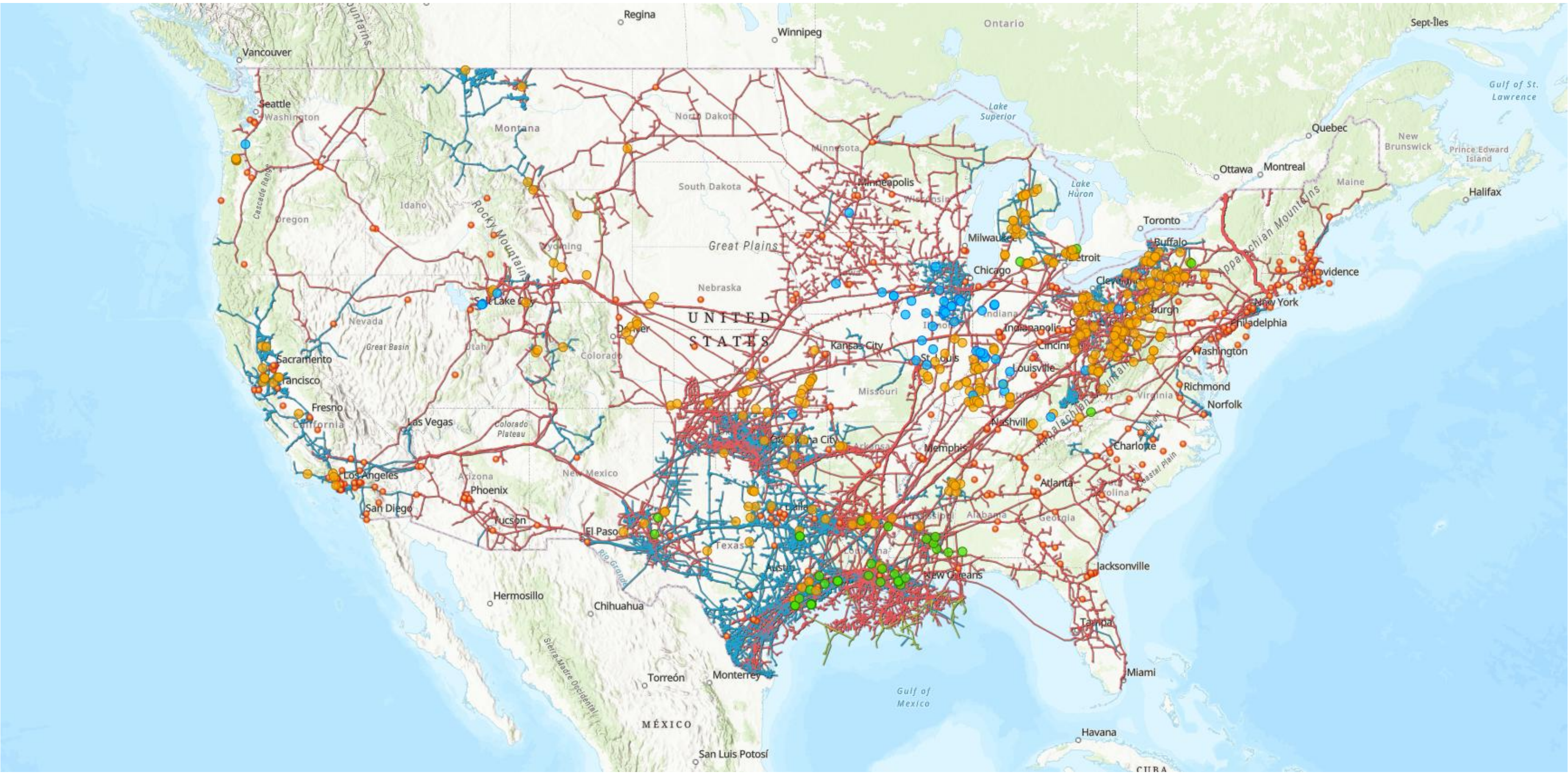
Vaporization – a step within the regasification process where a liquid physically changes to a gas.

Winter heating season – the period of time characterized by generally colder weather. Aligns with withdrawal season.

Withdrawal season – the period of time from November 1 through March 31 of each year during which natural gas is generally withdrawn from underground storage for use during the winter heating season.

Working gas – the volume of natural gas in underground storage that is available to be withdrawn to meet market demand.

Appendix C – Natural Gas Pipelines and Storage Assets Across the Lower 48



Source: ArcGIS Online

This map can be accessed via the following steps:

- Visit https://www.arcgis.com/home/webmap/viewer.html?webmap=your-map-id
- Map Layers:
  - Federal User Community. (2025, April). *Underground Natural Gas Storage* [Feature layer]. ArcGIS Online. https://www.arcgis.com/home/item.html?id=your-layer-id
  - Data source: U.S. Energy Information Administration
- HostedByHIFLD. (2025, April 8). *Above Ground Liquefied Natural Gas Storage Facilities* [Feature layer]. ArcGIS Online. https://www.arcgis.com/home/item.html?id=your-layer-id
  - Data source: Homeland Infrastructure Foundation-Level Data [HIFLD]
- Federal User Community. (2025, April 1). *Natural Gas Interstate and Intrastate Pipelines* [Feature layer]. ArcGIS Online. https://www.arcgis.com/home/item.html?id=your-layer-id
  - Data source: U.S. Energy Information Administration

Appendix D – Net Changes to Natural Gas Infrastructure Capacity and Market Indicators by State and Region

Natural Gas Market Expansion Metrics

2013-2023 Net Change*

Region	LNG Storage Capacity (Bcf)	Underground Storage Capacity (Bcf)	Intrastate Pipeline Capacity (Bcf/d)	Interstate Pipeline Capacity (Bcf/d)	Production (Bcf)	Demand (Bcf)
East	40.0	−8.5	1.1	24.5	8,353.4	2,618.0
Midwest	0.1	20.7	0.5	15.3	−63.8	1,044.1
Mountain	0.2	17.3	0.9	3.1	1,520.8	597.2
Pacific	0.0	11.2	0.3	0.4	−114.7	−226.6
South Central	0.0	64.6	23.4	35.2	4,454.8	2,328.7
Lower-48	**40.3**	**105.3**	**26.2**	**78.4**	**14,150.6**	**6,361.4**

**LNG Storage Capacity net changes represent 2014-2023*

Table: American Gas Association • Source: Energy Information Administration, Pipeline and Hazardous Materials Safety Administration • Created with Datawrapper

American Gas Association

Natural Gas Infrastructure Capacity and Market Indicator Metrics

2013-2023* Net Change, Billion Cubic Feet (Bcf)

Region	LNG Capacity	Underground Storage Capacity	Intrastate Pipeline Capacity (Bcf/d)	Interstate Pipeline Capacity (Bcf/d)	Production	Demand
East	**40.0**	**-8.5**	**1.1**	**24.5**	**8353.4**	**2618.0**
Connecticut	0.1	-	-	0.1	-	57.8
Delaware	0.0	-	-	0.2	-	−13.8
Florida	0.0	-	0.4	2.2	0.1	418.4
Georgia	0.0	-	0.0	1.6	-	156.6
Maine	0.0	-	-	0.2	-	−6.7
Maryland	0.0	0.0	-	1.1	0.0	95.1
Massachusetts	−0.1	-	-	0.6	-	−43.7
New Hampshire	0.0	-	0.0	0.0	-	3.7
New Jersey	0.0	-	-	2.6	-	16.4
New York	0.1	−3.0	0.0	1.7	−15.2	45.7
North Carolina	0.3	-	0.0	0.3	-	216.5
Ohio	-	−2.8	0.1	3.6	1996.5	441.7
Pennsylvania	39.7	−11.0	0.7	2.6	4252.2	751.7
Rhode Island	0.0	-	-	0.0	-	12.0
South Carolina	0.0	-	0.0	0.2	-	109.6
Vermont	-	-	0.0	0.0	-	2.9
Virginia	0.0	−0.5	0.0	1.2	−56.0	210.9
West Virginia	-	8.8	-	6.3	2175.8	143.2
Midwest	**0.1**	**20.7**	**0.5**	**15.3**	**-63.8**	**1044.1**
Illinois	0.0	18.9	0.1	3.2	−0.3	18.6
Indiana	0.0	2.8	0.0	0.7	−4.1	202.4
Iowa	0.0	0.0	0.0	0.0	-	122.8
Kentucky	-	0.0	-	4.1	−3.6	118.3
Michigan	-	−3.4	0.2	5.5	−53.8	249.9
Minnesota	0.0	0.0	0.0	0.1	-	38.5
Missouri	-	0.0	0.0	1.2	0.0	33.8
Tennessee	0.0	2.4	0.2	0.1	−1.9	111.1
Wisconsin	0.1	-	0.0	0.3	-	148.7

Region	LNG Capacity	Underground Storage Capacity	Intrastate Pipeline Capacity (Bcf/d)	Interstate Pipeline Capacity (Bcf/d)	Production	Demand
Mountain	**0.2**	**17.3**	**0.9**	**3.2**	**1520.8**	**597.2**
Arizona	0.1	-	0.0	0.0	0.0	190.4
Colorado	-	19.3	0.2	1.9	99.9	37.2
Idaho	0.0	-	0.0	-	2.4	38.7
Montana	0.0	−0.1	0.0	0.0	−21.6	11.8
Nebraska	0.0	0.0	-	0.1	−0.8	28.8
Nevada	0.0	-	-	0.0	0.0	16.0
New Mexico	-	0.0	0.1	0.3	1805.6	76.6
North Dakota	-	-	0.6	0.5	697.1	122.8
South Dakota	-	-	-	-	−16.1	13.5
Utah	0.2	0.0	0.0	0.0	−180.8	38.8
Wyoming		−2.0	0.0	0.3	−864.9	22.6
Pacific	**0.0**	**11.2**	**0.3**	**0.4**	**−114.7**	**−226.6**
California	0.0	4.3	0.0	0.2	−114.0	−328.1
Oregon	0.0	6.9	0.1	0.2	−0.7	59.8
Washington	0.0	0.0	0.2	0.0	-	41.8
South Central	**0.0**	**64.6**	**23.4**	**35.2**	**4454.8**	**2328.7**
Alabama	0.0	8.2	0.0	3.5	−102.9	135.2
Arkansas	0.0	0.1	-	0.0	−749.8	101.4
Kansas	-	−1.0	-	−0.3	−153.4	21.2
Louisiana	0.0	7.2	3.1	18.5	1984.7	598.8
Mississippi	0.0	26.6	-	1.9	−31.6	200.0
Oklahoma		2.1	0.8	1.3	700.5	168.7
Texas	0.0	21.4	19.4	10.2	2807.3	1103.3
Lower-48	**40.3**	**105.3**	**26.2**	**78.5**	**14150.6**	**6361.4**
Alaska	0.0	0.0	0.0	-	29.4	121.6
Hawaii	-	-	-	-	-	0.1
U.S. Total	**40.3**	**105.3**	**26.2**	**78.5**	**14179.9**	**6483.2**

**LNG Storage Capacity net change represents 2014-2023, Please Note: Totals may not foot due to rounding.*

Table: American Gas Association • Source: Energy Information Administration, Pipeline and Hazardous Materials Safety Administration • Created with Datawrapper

2025 Minnesota Gas Procurement Plan Overview

Prepared by CenterPoint Energy of Minnesota

October 9, 2025

Public Version

To the Department's knowledge, there is no public version of this document.

From:	Wynia, Donald W
To:	Kundert, John (COMM)
Subject:	RE: [External Email] 2025 Northern Lights CIAC
Date:	Tuesday, October 7, 2025 9:11:36 AM
Attachments:	image001.png

This message may be from an external email source.
Do not select links or open attachments unless verified. Report all suspicious emails to Minnesota IT Services Security Operations Center.

Good Morning John,

If we are funding the expansion with a CIAC, the payment is always due by at latest March 31st of in-service year – which was the case for NL 2025. Funds were sent to NNG the last week of March 2025. That does not mean we cannot pay the CIAC in advance of March 31st if we elect to.

Let me know if you have anymore questions. Have a good week.

-Donny

From: Kundert, John (COMM) <john.kundert@state.mn.us>
Sent: Monday, October 6, 2025 4:11 PM
To: Wynia, Donald W <donald.wynia@centerpointenergy.com>
Subject: [External Email] 2025 Northern Lights CIAC

Hi Donny –

I am working on our response comments in the 25-72 docket and I have a question for you. When did the Company pay the CIAC for the 2025 Northern Lights expansion? I am assuming it was in 2023 or 2024 since I imagine NNG wants the (CIAC) to fund the capacity expansion. Is that correct or am I missing something?

Thanks.

John Kundert
Financial Analyst
651-539-1740
mn.gov/commerce
Minnesota Department of Commerce
85 7th Place East, Suite 280 | Saint Paul, MN 55101

COMMERCE DEPARTMENT

State of Minnesota
Minnesota Department of Commerce

Utility Information Request

Docket Number: G-008/M-25-72 - Request for Change in Demand Units	Date of Request: 10/13/2025
Requested From: CENTERPOINT ENERGY MINNESOTA GAS	Response Due: 10/23/2025

Analyst Requesting Information: John Kundert, Lynn Behr

Type of Inquiry: Forecasting

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
DOC 031 - P	Topic: CenterPoint/Tenaska Asset Management Agreement (AMA) for 2025-2026 Summer Season Firm Capacity on Viking Gas Pipeline Reference(s): CenterPoint Amended Filing, Exhibit C5 **Request:** 1. Please provide a spreadsheet in executable format that provides an example of the calculation of the Net Optimization Value of the AMA and identifies the allocation of that same Net Opitmization Value. 2. Please provide a spreadsheet in executable format that provides the calculation of the Net Optimization Value of the AMA for the period from April 1, 2025 through November 1, 2025. 3. Please provide the Monthly Statement Payment with a written statement accounting of the results of TMV's optimization efforts for said prior month for each month covered by the agreement. Include the detail associated with the calculation of the Net Optimization Value, and the monthly Company Optimization Amount. 4. Please provide the final/summary accounting for this AMA in an executable format. **Response:** 1. See attachment *DOC 031 - Viking AMA_Tenaska*. (Attachment not provided in Public version as it contains Non-Public Information) This excel spreadsheet shows the monthly tracking for April 2025 to September 2025 of the volumes, margin, Tenaska Share 40% and

Response By: Kristal Dipuccio
Title: Manager, Gas Supply
Department: Gas Purchasing, Minnesota
Telephone: 713-207-5965

CenterPoint Share 60%. October 2025 results will be included once available. The margin dollars will be aggregated over the summer months and if a true-up is needed to meet the Net Optimization Value, the positive difference will be added to the invoice of the month immediately following the last month of the Release Term.

2. See response to 1.

3. See attachment *DOC 031 - Tenaska Viking AMA Sharing Invoices* for monthly statements, and *DOC 031 - Viking AMA_Tenaska* for summary of accounting. (Attachments not provided in Public version as it contains Non-Public Information)

4. See response to 3.

Response By: Kristal Dipuccio
Title: Manager, Gas Supply
Department: Gas Purchasing, Minnesota
Telephone: 713-207-5965

ANR Storage and Transportation Agreements - Summary of Costs Recovered via Demand-delivered Gas Costs

Description	Annual Cost ($/yr)	Allocation Factor	Demand-delivered Cost ($/yr)
ANR Storage			
FT3 Transport			
FT3 Transport			
FT1 Transport			
FT1 Transport			
Sum			

[TRADE SECRET DATA HAS BEEN EXCISED]

State of Minnesota
Minnesota Department of Commerce

<u>Utility Information Request</u>

Docket Number: G008/M-24-146 - Request for Change in Demand Units — Date of Request: 6/27/2024
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 7/8/2024

Analyst Requesting Information: Ashley Uphus/John Kundert

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
DOC 015 P	Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy. Topic: Preliminary approval to update swing reservation fees on November 1, 2024 Reference(s): Filing, Summary of Miscellaneous Tariff Filing Please provide a narrative that explains the purpose of the requested “preliminary approval” to update swing reservation fees on November 1, 2024. **Response:** The Company requests a preliminary approval of our swing reservation fees to be updated in a supplemental filing that is filed each November. The Company provides this in its initial requests knowing that the fees will change for the upcoming winter; however, at the time of filing the demand entitlement request, the Company does not have the exact fees. Since the request for proposal ("RFP") does not occur until later in the summer months, the Company does not have the specifics available for the demand entitlement filing. Therefore, the Company requests preliminary approval to inform the State that the Company is aware that the swing reservation will change for the winter months, but that at the time of filing the Company does not know the exact fees. The Company will submit a supplemental filing in November with the updated fees for swing reservation.

Response By: Kristal Dipuccio
Title: Manager, Gas Supply
Department: Gas Purchasing, Minnesota
Telephone: 713-207-5965

Summary of Changes to CenterPoint's Demand Entitlement - April-November 2025

Line No.	Month	Category	Description	Incremental - Dth/Day	Proposed Cost	Prior Cost	Incremental Cost
		[TRADE SECRET BEGINS					
1.	April						
2.	April						
3.	April						
4.	April						
5.	April						
6.	April						
7.	April						
8.	April						
9.	April						
10.	April						
11.	April						
12.							
12.	April						
13.	May						
14.	May						
14.	November						
15.	November						
16.	November						
17.	November						
18.	November						
19.	November						
							TRADE SECRET ENDS]
20.	April 2025 Annual Estimated Demand Cost				$173,965,593		
21.	2025-2026 AEDE Incremental Cost Increase				$18,766,457		
22.	November 2025 AEDE				$192,732,050		
23.	Percentage Increase April - November				10.8%		

Department Exhibit 1
Docket No. G008/M-25-72
CenterPoint Demand Entitlement Analysis

		Number of Firm Customers				Design Day Requirement			Total Entitlement Plus On-line Storage & Peak Shaving			Reserve Margin
		(1 A)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Docket No.	Heating Season	Actual Number of Jan. Customers	Projected DD Customers	Change from Previous Year	% Change From Previous Year	Design Day (Dk)	Change from Previous Year	% Change From Previous Year	Total Entitlement (Dk)	Entitlement Change from Previous Year	% Change From Previous Year	Corrected Reserve Margin [(7)-(4)]/(4)
25-72	2025-2026		935,964	8,693	0.94%	1,544,100	22,800	1.50%	1,580,100	10,370	0.66%	2.33%
24-146	2024-2025	926,654	927,271	7,626	0.83%	1,521,300	20,850	1.39%	1,569,730	27,943	1.81%	3.18%
23-221	2023-2024	921,885	919,645	7,725	0.85%	1,500,450	23,850	1.62%	1,541,787	21,503	1.41%	2.75%
22-306	2022-2023	911,310	911,920	13,580	1.51%	1,476,600	23,600	1.62%	1,520,284	-1,300	-0.09%	2.96%
21-523	2021-2022	901,383	898,340	12,679	1.43%	1,453,000	10,000	0.69%	1,521,584	69,000	4.75%	4.72%
20-565	2020-2021	890,385	885,661	1,097	0.12%	1,443,000	8,000	0.56%	1,452,584	1,300	0.09%	0.66%
19-278	2019-2020	878,543	884,564	19,211	2.22%	1,435,000	26,000	1.85%	1,451,284	41,688	2.96%	1.13%
18-462	2018-2019	868,105	865,353	8,261	0.96%	1,409,000	6,000	0.43%	1,409,596	0	0.00%	0.04%
17-533	2017-2018	858,548	857,092	6,520	0.77%	1,403,000	39,000	2.86%	1,409,596	34,126	2.48%	0.47%
16-571	2016-2017	847,780	850,572	9,437	1.12%	1,364,000	11,000	0.81%	1,375,470	19,519	1.44%	0.84%
15-644	2015-2016	839,291	841,135	11,133	1.34%	1,353,000	27,000	2.04%	1,355,951	11,533	0.86%	0.22%
14-561	2014-2015	830,377	830,002	6,212	0.75%	1,326,000	2,000	0.15%	1,344,418	4,479	0.33%	1.39%
13-578	2013-2014	821,220	823,790	12,651	1.56%	1,324,000	8,000	0.61%	1,339,939	-6,842	-0.51%	1.20%
12-864	2012-2013	813,605	811,139	3,212	0.40%	1,316,000	100,000	8.22%	1,346,781	-32,900	-2.38%	2.34%
11-1078	2011-2012	807,922	807,927	3,647	0.45%	1,216,000	3,000	0.25%	1,379,681	0	0.00%	13.46%
10-1162	2010-2011	804,703	804,280	3,104	0.39%	1,213,000	2,000	0.17%	1,379,681	40,000	2.99%	13.74%
09-1260	2009-2010	801,286	801,176	4,031	0.51%	1,211,000	-24,000	-1.94%	1,339,681 1/	9,615	0.72%	**10.63%**
08-1307	2008-2009	797,228	797,145	-10,815	-1.34%	1,235,000	-11,000	-0.88%	1,330,066 1/	873	0.07%	**7.70%**
07-561	2007-2008	792,950	807,960	15,025	1.89%	1,246,000	14,000	1.14%	1,329,193 1/	26,891	2.06%	**6.68%**
06-1533	2006-2007	787,326	792,935	16,585	2.14%	1,232,000	12,000	0.98%	1,302,302	2,000	0.15%	5.71%
05-1736	2005-2006	777,424	776,350	17,129	2.26%	1,220,000	-44,000	-3.48%	1,300,302	4,500	0.35%	6.58%
	2004-2005	762,835	759,221	14,710	1.98%	1,264,000	21,000	1.69%	1,295,802	0	0.00%	2.52%
	2003-2004**	745,890	744,511	18,603	2.56%	1,243,000	29,300	2.41%	1,295,802	34,400	2.73%	4.25%
	2002-2003**	728,005	725,908	16,524	2.33%	1,213,700	30,092	2.54%	1,261,402	12,500	1.00%	3.93%
	2001-2002		709,384			1,183,608			1,248,902			5.52%
	Average Per Year:		826,387	9,473	1.18%	1,325,069	14,682	1.12%	1,379,242	13,949	1.01%	4.28%

		Firm Peak Day Sendout			Per Customer Metrics				
		(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Docket No.	Heating Season	Firm Peak Day Sendout (Dk)	Change from Previous Year	% Change From Previous Year	Excess per Customer [(7) - (4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per Customer (7)/(1)	Peak Day Sendout per DD # Customer (11)/(1)	Peak Day Sendout per Actual Customers (11)/(1 A)
25-72	2025-2026	n/a	n/a	n/a					
24-146	2024-2025	1,281,973	194,570	17.89%	0.0522	1.6406	1.6928	1.3825	1.3834
23-221	2023-2024	1,087,403	(54,055)	-4.74%	0.0449	1.6316	1.6765	1.1824	1.1795
22-306	2022-2023	1,141,458	36,668	3.32%	0.0479	1.6192	1.6671	1.2517	1.2525
21-523	2021-2022	1,104,790	(41,811)	-3.65%	0.0763	1.6174	1.6938	1.2298	1.2257
20-565	2020-2021	1,146,601	119,943	11.68%	0.0108	1.6293	1.6401	1.2946	1.2878
19-278	2019-2020	1,026,658	(226,861)	-18.10%	0.0184	1.6223	1.6407	1.1606	1.1686
18-462	2018-2019	1,253,519	163,897	15.04%	0.0007	1.6282	1.6289	1.4486	1.4440
17-533	2017-2018	1,089,622	110,691	11.31%	0.0077	1.6369	1.6446	1.2713	1.2691
16-571	2016-2017	978,931	(15,215)	-1.53%	0.0135	1.6036	1.6171	1.1509	1.1547
15-644	2015-2016	994,146	34,156	3.56%	0.0035	1.6085	1.6120	1.1819	1.1845
14-561	2014-2015	959,990	(126,340)	-11.63%	0.0222	1.5976	1.6198	1.1566	1.1561
13-578	2013-2014	1,086,330	125,196	13.03%	0.0193	1.6072	1.6266	1.3187	1.3228
12-864	2012-2013	961,134	130,690	15.74%	0.0379	1.6224	1.6604	1.1849	1.1813
11-1078	2011-2012	830,444	(42,328)	-4.85%	0.2026	1.5051	1.7077	1.0279	1.0279
10-1162	2010-2011	872,772	(21,153)	-2.37%	0.2072	1.5082	1.7154	1.0852	1.0846
09-1260	2009-2010	893,925	(130,839)	-12.77%	0.1606	1.5115	1.6721	1.1158	1.1156
08-1307	2008-2009	1,024,764	21,335	2.13%	0.1193	1.5493	1.6685	1.2855	1.2854
07-561	2007-2008	1,003,429	5,627	0.56%	0.1030	1.5422	1.6451	1.2419	1.2654
06-1533	2006-2007	997,802	140,866	16.44%	0.0887	1.5537	1.6424	1.2584	1.2673
05-1736	2005-2006	856,936	(87,406)	-9.26%	0.1034	1.5715	1.6749	1.1038	1.1023
	2004-2005	944,342	(69,052)	-6.81%	0.0419	1.6649	1.7068	1.2438	1.2379
	2003-2004	1,013,394	97,281	10.62%	0.0709	1.6696	1.7405	1.3612	1.3586
	2002-2003	916,113	122,670	15.46%	0.0657	1.6720	1.7377	1.2620	1.2584
	2001-2002	793,443			0.0920	1.6685	1.7605	1.1185	
	Average Per Year:	999,041	13,362	1.96%	0.0678	1.6018	1.6695	1.2146	1.2196

All the numbers reflected in the above tables are consolidated for the Company's previous Northern and Viking service areas.
* = Projected Values
** = From CenterPoint's Exh. B, page 3 in Docket No. G008/M-08-1307.
1/ Corrected total entitlement amounts for peak-shaving output. See Docket No. G008/M-10-1162.

Department Attachment 2.a
Docket No. G008/M-25-72 - October 31, 2025 Compliance Filing
March - April 2025 - Annual Demand Cost Impact by Rate Schedule

Residential	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	March 1, 2025 PGA	April 1, 2025 (G008/AA-25-72)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.3692	$3.2671	-23.85%	24.28%	-3.03%	($0.1021)
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.4443	$1.5017	16.52%	3.97%	3.97%	$0.0574
Commodity Margin (2) (3) (5)	$2.5043	$2.9019	$2.9797	$2.9797	18.98%	2.68%	0.00%	$0.0000
Total Cost of Gas	$8.0836	$6.9751	$7.7932	$7.7485	-4.15%	11.09%	-0.57%	($0.0447)
Average Annual Usage (Dk)	89	89	89	89				
Average Annual Total Cost of Gas	$719.44	$620.78	$693.59	$689.62	-4.15%	11.09%	-0.57%	($3.98)
Average Annual Total Demand Cost of Gas								$5.11

Commercial/Industrial Firm - A	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	March 1, 2025 PGA	April 1, 2025 (G008/AA-25-72)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.3692	$3.2671	-23.85%	24.28%	-3.03%	($0.1021)
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.4443	$1.5017	16.52%	3.97%	3.97%	$0.0574
Commodity Margin (2) (3) (5)	$2.6411	$3.8897	$3.8897	$3.8897	47.28%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.2204	$7.9629	$8.7032	$8.6585	5.33%	8.74%	-0.51%	($0.0447)
Average Annual Usage (Dk)	81	81	81	81				
Average Annual Total Cost of Gas	$664.21	$643.40	$703.22	$701.34	5.59%	9.00%	-0.27%	($1.88)
Average Annual Total Demand Cost of Gas								$4.65

Commercial/Industrial Firm - B	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	March 1, 2025 PGA	April 1, 2025 (G008/AA-25-72)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.3692	$3.2671	-23.85%	24.28%	-3.03%	($0.1021)
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.4443	$1.5017	16.52%	3.97%	3.97%	$0.0574
Commodity Margin (2) (3) (5)	$2.0380	$2.4691	$2.4691	$2.4691	21.15%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.6173	$6.5423	$7.2826	$7.2379	-4.98%	10.63%	-0.61%	($0.0447)
Average Annual Usage (Dk)	730	730	730	730				
Average Annual Total Cost of Gas	$5,560.63	$4,775.88	$5,316.30	$5,283.67	-4.98%	10.63%	-0.61%	($32.63)
Average Annual Total Demand Cost of Gas								$41.90

Commercial/Industrial Firm - C	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	March 1, 2025 PGA	April 1, 2025 (G008/AA-25-72)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.3692	$3.2671	-23.85%	24.28%	-3.03%	($0.1021)
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.4443	$1.5017	16.52%	3.97%	3.97%	$0.0574
Commodity Margin (2) (3) (5)	$1.7360	$1.9325	$1.9325	$1.9325	11.32%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.3153	$6.0057	$6.7460	$6.7013	-8.39%	11.58%	-0.66%	($0.0447)
Average Annual Usage (Dk)	12,076	12,076	12,076	12,076				
Average Annual Total Cost of Gas	$88,336.64	$72,522.43	$81,462.00	$80,922.22	-8.39%	11.58%	-0.66%	($539.78)
Average Annual Total Demand Cost of Gas								$693.14
			$17,440.79	$18,133.93	$693.14			

Large General Service	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	March 1, 2025 PGA	April 1, 2025 (G008/AA-25-72)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$3.1141	$3.3692	$3.2671	-23.85%	4.91%	-3.03%	($0.1021)
Commodity Margin (2) (3) (5)	$0.8301	$1.0029	$1.0029	$1.0807	30.19%	7.76%	7.76%	$0.0778
Commodity Charges	$5.1206	$4.1170	$4.3721	$4.3478	-15.09%	5.61%	-0.56%	($0.0243)
LV Demand Cost of Gas (1)	$9.9733	$12.8270	$12.8270	$15.7572	57.99%	22.84%	22.84%	$2.9302
LV Demand Delivery Charge	$4.8303	$6.3303	$6.3303	$6.3303	31.05%	0.00%	0.00%	$0.0000
Average Annual Usage (Dk)	47,751	47,751	47,751	47,751				
Average Daily MDQ Usage (Dk)	7,282	8,448	8,448	7,150				
Average Annual Total Cost of Gas	$352,314	$358,432	$370,613	$365,537	3.75%	1.98%	-1.37%	($5,075.59)
Average Annual Total Demand Cost of Gas								$20,950.93

Summary of Most Recent PGA

Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	-$0.1021	-3.03%	$0.0574	3.97%	$5.11	($3.98)	-0.57%
Commercial/Industrial Firm A	-$0.1021	-3.03%	$0.0574	3.97%	$4.65	($1.88)	-0.27%
Commercial/Industrial Firm B	-$0.1021	-3.03%	$0.0574	3.97%	$41.90	($32.63)	-0.61%
Commercial/Industrial Firm C	-$0.1021	-3.03%	$0.0574	3.97%	$693.14	($539.78)	-0.66%
Large General Service	-$0.1021	-3.03%	$2.9302	22.84%	$20,950.93	($5,075.59)	-1.37%

(1) Does not include Demand Smoothing Adjustment.
(2) Does not reflect Decoupling Factor, GAP, Interim or GCR Factors.
(3) 2021 Rate Case - tariff values for Last Rate Case and Last Demand Charge. Reflects base rate plus CCRA (As of 11/2023 $0.0926 per DT).
(4) Actual WACOG for historical timeframes / 2021 Rate Case Base value in Settlement.

Department Attachment 2.b
Docket No. G008/M-25-72 - October 31, 2025 Compliance Filing
April to May 2025 - Annual Demand Cost Impact by Rate Schedule

Residential	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	April 1, 2025 (G008/AA-25-72)	May 1, 2025	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.2671	$2.5965	-39.48%	-1.23%	-20.53%	($0.6706)
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.5017	$1.5463	19.98%	7.06%	2.97%	$0.0446
Commodity Margin (2) (3) (5)	$2.5043	$2.9019	$2.9797	$2.9797	18.98%	2.68%	0.00%	$0.0000
Total Cost of Gas	$8.0836	$6.9751	$7.7485	$7.1225	-11.89%	2.11%	-8.08%	($0.6260)
Average Annual Usage (Dk)	89	89	89	89				
Average Annual Total Cost of Gas	$719.44	$620.78	$689.62	$633.90	-11.89%	2.11%	-8.08%	($55.71)
Average Annual Total Demand Cost of Gas								$3.97

Commercial/Industrial Firm - A	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	April 1, 2025 (G008/AA-25-72)	May 1, 2025	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.2671	$2.5965	-39.48%	-1.23%	-20.53%	($0.6706)
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.5017	$1.5463	19.98%	7.06%	2.97%	$0.0446
Commodity Margin (2) (3) (5)	$2.6411	$3.8897	$3.8897	$3.8897	47.28%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.2204	$7.9629	$8.6585	$8.0325	-2.29%	0.87%	-7.23%	($0.6260)
Average Annual Usage (Dk)	81	81	81	81				
Average Annual Total Cost of Gas	$664.21	$643.40	$699.61	$650.63	-2.04%	1.12%	-7.00%	($48.98)
Average Annual Total Demand Cost of Gas								$3.61

Commercial/Industrial Firm - B	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	April 1, 2025 (G008/AA-25-72)	May 1, 2025	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.2671	$2.5965	-39.48%	-1.23%	-20.53%	($0.6706)
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.5017	$1.5463	19.98%	7.06%	2.97%	$0.0446
Commodity Margin (2) (3) (5)	$2.0380	$2.4691	$2.4691	$2.4691	21.15%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.6173	$6.5423	$7.2379	$6.6119	-13.20%	1.06%	-8.65%	($0.6260)
Average Annual Usage (Dk)	730	730	730	730				
Average Annual Total Cost of Gas	$5,560.63	$4,775.88	$5,283.67	$4,826.69	-13.20%	1.06%	-8.65%	($456.98)
Average Annual Total Demand Cost of Gas								$32.56

Commercial/Industrial Firm - C	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	April 1, 2025 (G008/AA-25-72)	May 1, 2025	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.2671	$2.5965	-39.48%	-1.23%	-20.53%	($0.6706)
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.5017	$1.5463	19.98%	7.06%	2.97%	$0.0446
Commodity Margin (2) (3) (5)	$1.7360	$1.9325	$1.9325	$1.9325	11.32%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.3153	$6.0057	$6.7013	$6.0753	-16.95%	1.16%	-9.34%	($0.6260)
Average Annual Usage (Dk)	12,076	12,076	12,076	12,076				
Average Annual Total Cost of Gas	$88,336.64	$72,522.43	$80,922.22	$73,362.90	-16.95%	1.16%	-9.34%	($7,559.33)
Average Annual Total Demand Cost of Gas								$538.57

Large General Service	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	April 1, 2025 (G008/AA-25-72)	May 1, 2025	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$3.1141	$3.2671	$2.5965	-39.48%	-16.62%	-20.53%	($0.6706)
Commodity Margin (2) (3) (5)	$0.8301	$1.0029	$1.0807	$1.0807	30.19%	7.76%	0.00%	$0.0000
Commodity Charges	$5.1206	$4.1170	$4.3478	$3.6772	-28.19%	-10.68%	-15.42%	($0.6706)
LV Demand Cost of Gas (1)	$9.9733	$12.3733	$15.7572	$16.2259	62.69%	31.14%	2.97%	$0.4687
LV Demand Delivery Charge	$4.8303	$6.3303	$6.3303	$6.3303	31.05%	0.00%	0.00%	$0.0000
Average Annual Usage (Dk)	47,751	47,751	47,751	47,751				
Average Daily MDQ Usage (Dk)	7,282	8,448	7,150	7,150				
Average Annual Total Cost of Gas	$352,314	$354,599	$365,537	$336,867	-4.38%	-5.00%	-7.84%	($28,670.62)
Average Annual Total Demand Cost of Gas								$3,351.21

Summary of Most Recent PGA

Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	-$0.6706	-20.53%	$0.0446	2.97%	$3.97	($55.71)	-8.08%
Commercial/Industrial Firm A	-$0.6706	-20.53%	$0.0446	2.97%	$3.61	($48.98)	-7.00%
Commercial/Industrial Firm B	-$0.6706	-20.53%	$0.0446	2.97%	$32.56	($456.98)	-8.65%
Commercial/Industrial Firm C	-$0.6706	-20.53%	$0.0446	2.97%	$538.57	($7,559.33)	-9.34%
Large General Service	-$0.6706	-20.53%	$0.4687	2.97%	$3,351.21	($28,670.62)	-7.84%

(1) Does not include Demand Smoothing Adjustment.
(2) Does not reflect Decoupling Factor, GAP, Interim or GCR Factors.
(3) 2021 Rate Case - tariff values for Last Rate Case and Last Demand Charge. Reflects base rate plus CCRA (As of 11/2023 $0.0926 per DT).
(4) Actual WACOG for historical timeframes / 2021 Rate Case Base value in Settlement.

Department Attachment 2.c
Docket No. G008/M-25-72 - October 31, 2025 Compliance Filing
October to November 2025 Annual Demand Cost Impact by Rate Schedule

Residential	**Last Rate Case (G008/MR-21-435)**	Last Demand Change November 1, 2024 (G008/M-24-146)	October 1, 2025	Nov 1, 2025	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From October 1 PGA	Change ($) From October 1 PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$2.4332	$3.4305	-20.04%	30.49%	40.99%	$0.9973
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.5463	$1.5333	18.97%	6.16%	-0.84%	($0.0130)
Commodity Margin (2) (3) (5)	$2.5043	$2.9019	$2.9797	$2.9797	18.98%	2.68%	0.00%	$0.0000
Total Cost of Gas	$8.0836	$6.9751	$6.9592	$7.9435	-1.73%	13.88%	14.14%	$0.9843
Average Annual Usage (Dk)	89	89	89	89				
Average Annual Total Cost of Gas	$719.44	$620.78	$619.37	$706.97	-1.73%	13.88%	14.14%	$87.60
Average Annual Total Demand Cost of Gas								($1.16)

Commercial/Industrial Firm - A	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	October 1, 2025	Nov 1, 2025	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From October 1 PGA	Change ($) From October 1 PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$2.4332	$3.4305	-20.04%	30.49%	40.99%	$0.9973
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.5463	$1.5333	18.97%	6.16%	-0.84%	($0.0130)
Commodity Margin (2) (3) (5)	$2.6411	$3.8897	$3.8897	$3.8897	47.28%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.2204	$7.9629	$7.8692	$8.8535	7.70%	11.18%	12.51%	$0.9843
Average Annual Usage (Dk)	81	81	81	81				
Average Annual Total Cost of Gas	$664.21	$643.40	$635.83	$717.13	7.97%	11.46%	12.79%	$81.30
Average Annual Total Demand Cost of Gas								($1.05)

Commercial/Industrial Firm - B	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	October 1, 2025	Nov 1, 2025	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From October 1 PGA	Change ($) From October 1 PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$2.4332	$3.4305	-20.04%	30.49%	40.99%	$0.9973
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.5463	$1.5333	18.97%	6.16%	-0.84%	($0.0130)
Commodity Margin (2) (3) (5)	$2.0380	$2.4691	$2.4691	$2.4691	21.15%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.6173	$6.5423	$6.4486	$7.4329	-2.42%	13.61%	15.26%	$0.9843
Average Annual Usage (Dk)	730	730	730	730				
Average Annual Total Cost of Gas	$5,560.63	$4,775.88	$4,707.48	$5,426.02	-2.42%	13.61%	15.26%	$718.54
Average Annual Total Demand Cost of Gas								($9.49)

Commercial/Industrial Firm - C	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	October 1, 2025	Nov 1, 2025	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From October 1 PGA	Change ($) From October 1 PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$2.4332	$3.4305	-20.04%	30.49%	40.99%	$0.9973
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.5463	$1.5333	18.97%	6.16%	-0.84%	($0.0130)
Commodity Margin (2) (3) (5)	$1.7360	$1.9325	$1.9325	$1.9325	11.32%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.3153	$6.0057	$5.9120	$6.8963	-5.73%	14.83%	16.65%	$0.9843
Average Annual Usage (Dk)	12,076	12,076	12,076	12,076				
Average Annual Total Cost of Gas	$88,336.64	$72,522.43	$71,390.95	$83,276.96	-5.73%	14.83%	16.65%	$11,886.01
Average Annual Total Demand Cost of Gas								($156.98)

Large General Service	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	October 1, 2025	Nov 1, 2025	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From October 1 PGA	Change ($) From October 1 PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$3.1141	$2.4332	$3.4305	-20.04%	10.16%	40.99%	$0.9973
Commodity Margin (2) (3) (5)	$0.8301	$1.0029	$1.0807	$1.0807	30.19%	7.76%	0.00%	$0.0000
Commodity Charges	$5.1206	$4.1170	$3.5139	$4.5112	-11.90%	9.57%	28.38%	$0.9973
LV Demand Cost of Gas (1)	$9.9733	$12.3733	$16.2259	$16.3159	63.60%	31.86%	0.55%	$0.0900
LV Demand Delivery Charge	$4.8303	$6.3303	$6.3303	$6.3303	31.05%	0.00%	0.00%	$0.0000
Average Annual Usage (Dk)	47,751	47,751	47,751	47,751				
Average Daily MDQ Usage (Dk)	7,282	8,448	7,150	7,150				
Average Annual Total Cost of Gas	$352,314	$354,599	$329,069	$377,335	7.10%	6.41%	14.67%	$48,265.57
Average Annual Total Demand Cost of Gas								$643.50

Summary of Most Recent PGA

Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	$0.9973	40.99%	-$0.0130	-0.84%	($1.16)	$87.60	14.14%
Commercial/Industrial Firm A	$0.9973	40.99%	-$0.0130	-0.84%	($1.05)	$81.30	12.79%
Commercial/Industrial Firm B	$0.9973	40.99%	-$0.0130	-0.84%	($9.49)	$718.54	15.26%
Commercial/Industrial Firm C	$0.9973	40.99%	-$0.0130	-0.84%	($156.98)	$11,886.01	16.65%
Large General Service	$0.9973	40.99%	$0.0900	0.55%	$643.50	$48,265.57	14.67%

(1) Does not include Demand Smoothing Adjustment.
(2) Does not reflect Decoupling Factor, GAP, Interim or GCR Factors.
(3) 2021 Rate Case - tariff values for Last Rate Case and Last Demand Charge. Reflects base rate plus CCRA (As of 11/2023 $0.0926 per DT).
(4) Actual WACOG for historical timeframes / 2021 Rate Case Base value in Settlement.

Department Attachment 2.d
Docket No. G008/M-25-72 - October 31, 2025 Compliance Filing
March - November 2025 Annual Demand Cost Impact by Rate Schedule

Residential	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	March 1, 2025 PGA	November 1, 2025 (G008/AA-25-72)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.3692	$3.4305	-20.04%	30.49%	1.82%	$0.0613
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.4443	$1.5333	18.97%	6.16%	6.16%	$0.0890
Commodity Margin (2) (3) (5)	$2.5043	$2.9019	$2.9797	$2.9797	18.98%	2.68%	0.00%	$0.0000
Total Cost of Gas	$8.0836	$6.9751	$7.7932	$7.9435	-1.73%	13.88%	1.93%	$0.1503
Average Annual Usage (Dk)	89	89	89	89				
Average Annual Total Cost of Gas	$719.44	$620.78	$693.59	$706.97	-1.73%	13.88%	1.93%	$13.38
Average Annual Total Demand Cost of Gas								$7.92

Commercial/Industrial Firm - A	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	March 1, 2025 PGA	November 1, 2025 (G008/AA-25-72)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.3692	$3.4305	-20.04%	30.49%	1.82%	$0.0613
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.4443	$1.5333	18.97%	6.16%	6.16%	$0.0890
Commodity Margin (2) (3) (5)	$2.6411	$3.8897	$3.8897	$3.8897	47.28%	0.00%	0.00%	$0.0000
Total Cost of Gas	$8.2204	$7.9629	$8.7032	$8.8535	7.70%	11.18%	1.73%	$0.1503
Average Annual Usage (Dk)	81	81	81	81				
Average Annual Total Cost of Gas	$664.21	$643.40	$703.22	$717.13	7.97%	11.46%	1.98%	$13.91
Average Annual Total Demand Cost of Gas								$7.21

Commercial/Industrial Firm - B	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	March 1, 2025 PGA	November 1, 2025 (G008/AA-25-72)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.3692	$3.4305	-20.04%	30.49%	1.82%	$0.0613
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.4443	$1.5333	18.97%	6.16%	6.16%	$0.0890
Commodity Margin (2) (3) (5)	$2.0380	$2.4691	$2.4691	$2.4691	21.15%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.6173	$6.5423	$7.2826	$7.4329	-2.42%	13.61%	2.06%	$0.1503
Average Annual Usage (Dk)	730	730	730	730				
Average Annual Total Cost of Gas	$5,560.63	$4,775.88	$5,316.30	$5,426.02	-2.42%	13.61%	2.06%	$109.72
Average Annual Total Demand Cost of Gas								$64.97

Commercial/Industrial Firm - C	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	March 1, 2025 PGA	November 1, 2025 (G008/AA-25-72)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$2.6289	$3.3692	$3.4305	-20.04%	30.49%	1.82%	$0.0613
Demand Cost of Gas (1)	$1.2888	$1.4443	$1.4443	$1.5333	18.97%	6.16%	6.16%	$0.0890
Commodity Margin (2) (3) (5)	$1.7360	$1.9325	$1.9325	$1.9325	11.32%	0.00%	0.00%	$0.0000
Total Cost of Gas	$7.3153	$6.0057	$6.7460	$6.8963	-5.73%	14.83%	2.23%	$0.1503
Average Annual Usage (Dk)	12,076	12,076	12,076	12,076				
Average Annual Total Cost of Gas	$88,336.64	$72,522.43	$81,462.00	$83,276.96	-5.73%	14.83%	2.23%	$1,814.96
Average Annual Total Demand Cost of Gas								$1,074.73

Large General Service	Last Rate Case (G008/MR-21-435)	Last Demand Change November 1, 2024 (G008/M-24-146)	March 1, 2025 PGA	November 1, 2025 (G008/AA-25-72)	Change From Last Rate Case	Change From Last Demand Change	Percent Change (%) From Most Recent PGA	Change ($) From Most Recent PGA
Commodity Cost of Gas (WACOG) (4)	$4.2905	$3.1141	$3.3692	$3.4305	-20.04%	10.16%	1.82%	$0.0613
Commodity Margin (2) (3) (5)	$0.8301	$1.0029	$1.0029	$1.0807	30.19%	7.76%	7.76%	$0.0778
Commodity Charges	$5.1206	$4.1170	$4.3721	$4.5112	-11.90%	9.57%	3.18%	$0.1391
LV Demand Cost of Gas (1)	$9.9733	$12.3733	$12.8270	$16.3159	63.60%	31.86%	27.20%	$3.4889
LV Demand Delivery Charge	$4.8303	$6.3303	$6.3303	$6.3303	31.05%	0.00%	0.00%	$0.0000
Average Annual Usage (Dk)	47,751	47,751	47,751	47,751				
Average Daily MDQ Usage (Dk)	7,282	8,448	8,448	7,150				
Average Annual Total Cost of Gas	$352,314	$354,599	$370,615	$377,335	7.10%	6.41%	1.81%	$6,719.64
Average Annual Total Demand Cost of Gas								$24,945.64

Summary of Most Recent PGA

Customer Class	Commodity Change ($/Dk)	Commodity Change (Percent)	Demand Change ($/Dk)	Demand Change (Percent)	Demand Annual Change ($/Dk)	Total Annual Change ($/Dk)	Total Annual Change (Percent)
Residential	$0.0613	1.82%	$0.0890	6.16%	$7.92	$13.38	1.93%
Commercial/Industrial Firm A	$0.0613	1.82%	$0.0890	6.16%	$7.21	$13.91	1.98%
Commercial/Industrial Firm B	$0.0613	1.82%	$0.0890	6.16%	$64.97	$109.72	2.06%
Commercial/Industrial Firm C	$0.0613	1.82%	$0.0890	6.16%	$1,074.73	$1,814.96	2.23%
Large General Service	$0.0613	1.82%	$3.4889	27.20%	$24,945.64	$6,719.64	1.81%

(1) Does not include Demand Smoothing Adjustment.
(2) Does not reflect Decoupling Factor, GAP, Interim or GCR Factors.
(3) 2021 Rate Case - tariff values for Last Rate Case and Last Demand Charge. Reflects base rate plus CCRA (As of 11/2023 $0.0926 per DT).
(4) Actual WACOG for historical timeframes / 2021 Rate Case Base value in Settlement.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Response Comments

Docket No. G008/M-25-72

Dated this **20th** day of **November 2025**

/s/Sharon Ferguson

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Christina	Benning	christina.benning@centerpointenergy.com	CenterPoint Energy Minnesota Gas			Electronic Service		No	M-25-72
2	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission		Electronic Service		Yes	M-25-72
3	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-72
4	Melodee	Carlson Chang	melodee.carlsonchang@centerpointenergy.com	CenterPoint Energy		505 Nicollet Mall Minneapolis MN, 55402 United States	Electronic Service		No	M-25-72
5	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	M-25-72
6	Seth	DeMerritt	seth.demerritt@centerpointenergy.com	CenterPoint Energy Minnesota Gas		505 Nicollet Mall Minneapolis MN, 55402 United States	Electronic Service		No	M-25-72
7	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	M-25-72
8	Jason	Loos	jason.loos@centerpointenergy.com	CenterPoint Energy Resources Corp.		505 Nicollet Mall 3rd Floor Minneapolis MN, 55402 United States	Electronic Service		No	M-25-72
9	Stacey	Murphree	stacey.murphree@centerpointenergy.com	CenterPoint Energy Minnesota Gas			Electronic Service		No	M-25-72
10	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	M-25-72
11	Donald	Wynia	donald.wynia@centerpointenergy.com	CenterPoint Energy		CenterPoint Energy 505 Nicollet Mall Minneapolis MN, 55402 United States	Electronic Service		No	M-25-72